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OCCIDENTAL VERTICAL MODIFIED IN SITU PROCESS FOR THE RECOVERY OF OIL FROM OIL SHALE: PHASE II

Annual Progress Report for June 1, 1980—May 31, 1981

By
Reid M. Nelson

MASTER

November 1981
Date Published

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Occidental Oil Shale, Inc.
Grand Junction, Colorado

U. S. DEPARTMENT OF ENERGY

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Annual Progress Report for the Period
June 1, 1980 through May 31, 1981

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Project Manager

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Date Published -- November 1981

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I. INTRODUCTION

On April 1, 1981, DOE (through the Laramie Energy Technology Center) officially notified Occidental Oil Shale, Inc., that DOE's funding of its share of the Cooperative Agreement scope of work will end upon the expenditure of the $37,814,140 presently obligated or on September 30, 1981, whichever comes first. OOSI intends to substantially complete the major tasks in the Agreement through the processing and shutdown of Retorts 7 and 8.

The progress presented in this report covers the period June 1, 1980, through May 31, 1981, under the work scope for Phase II of the Department of Energy/Occidental Oil Shale, Inc., DOE/OOSI, Cooperative Agreement. This report covers the second year of the Phase II program at Logan Wash, Colorado, where the technical feasibility demonstration of OOSI's vertical modified in situ oil shale retorting process (MIS) is being undertaken in concert with the development of the commercial C-b Tract in Rio Blanco County, Colorado.

Among activities at OOSI's Logan Wash site during this period were: mining of access drifts, mining to create the retort voids, continued construction of surface buildings, ignition of Mini-Retorts 3 and 4 to obtain information and data needed for the successful ignition of Retorts 7 and 8, rubbling and cleanup of Retorts 7, 8, and 8X, and development of the R7 and 8 sampling program. Also, installation of instrumentation for processing and construction of the bulkheads were begun for R7 and 8, which are two side-by-side commercial-size retorts in a three-level design.

Retort 8X, a partial retort, was rubbled January 24, 1981, Retort 7 on February 21, and Retort 8 on April 4. Mini-Retort 4, a three-level retort funded under the OOSI Rock Fragmentation Program, was rubbled on June 13, 1980. R7 and 8 ignition and simultaneous processing will commence in the fall of 1981. OOSI elected to operate MR3 and MR4 beyond ignition. The data collected from

the operation of these retorts will be published with the Retorts 7 and 8 processing data.

Appendix A of this report contains a list of Phase II Progress Reports available through the Department of Energy, Technical Information Center.

II. RETORTS 7, 8, 8X, MR3 and MR4

Work throughout the second year of Phase II of the Agreement continued on the three-level design for Retorts 7 and 8, Figure 1. Void and access drift mining progressed on four levels: upper, intermediate, lower and product collection. Figure 2 illustrates the design configuration. Partial Retort 8X serves a three-fold purpose. Prior to rubbling R7 and 8, R8X was rubbled to provide a final full-scale check on the explosives being used. Also it provided a dry run of the loading and blast procedure. Its primary purpose will be to provide data on the permeability of the 50-foot separation pillar betweem R8 and 8X.

Mini-Retorts 3 and 4, formed under the OOSI-funded Rock Fragmentation program, were used for ignition and burner tests during the latter part of the year. MR4 was ignited using a hot inert gas generator (HIGG) which input the gas through a bulkhead at one side of the retort. The first ignition test on MR3 failed in November 1980 because of burner problems. However, MR3 was ignited in April 1981 using an improved down hole burner at the center top of the retort. Both mini-retorts were designed specifically for the ignition tests under the Cooperative Agreement. OOSI operated these retorts beyond the ignition phase. The data taken during MR3 and MR4 processing will be published with the Retorts 7 and 8 processing data.

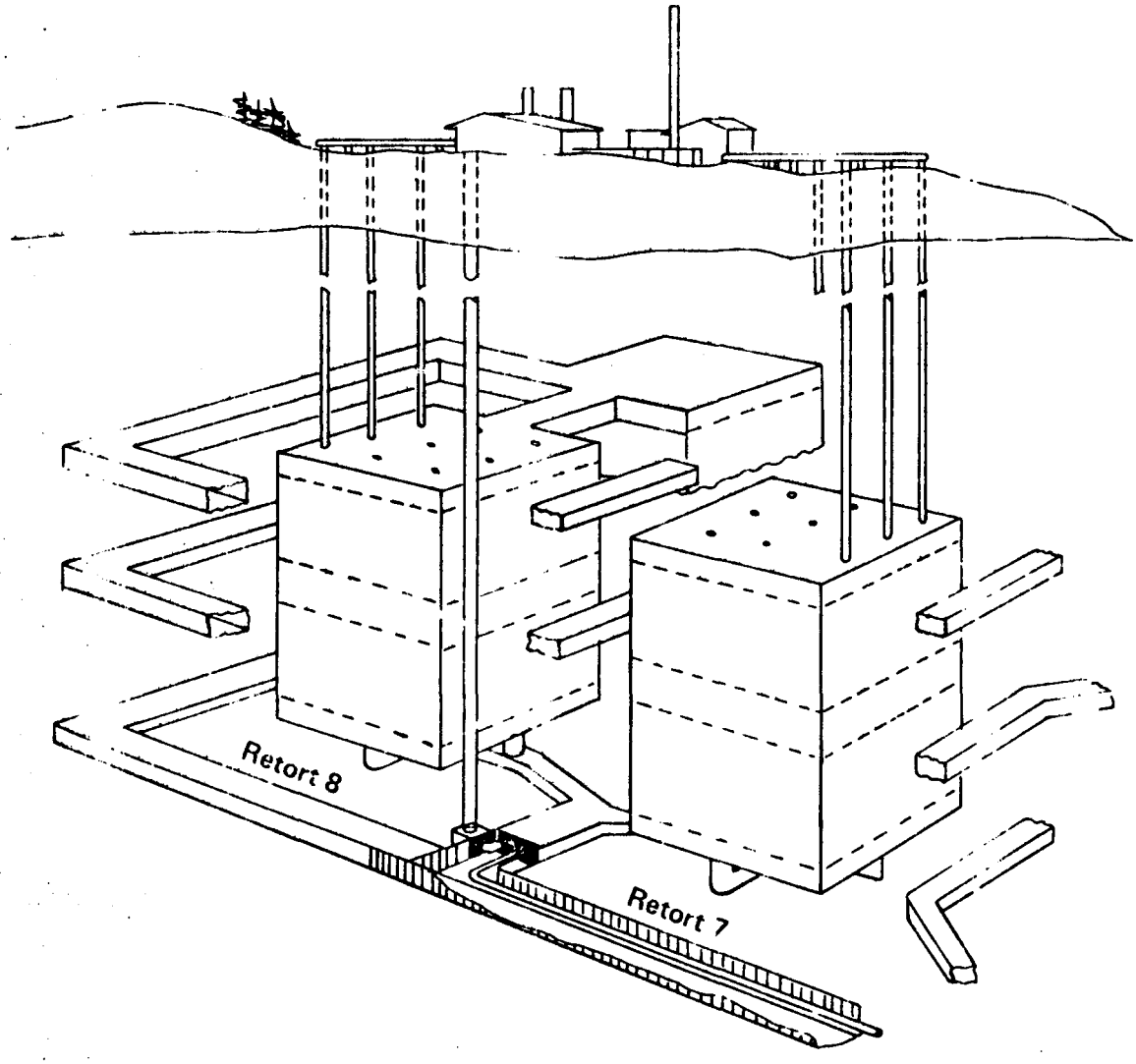


Figure 1. Schematic of Retorts 7 and 8 with a partial retort, 8X, situated behind Retort 8. The schematic has the access and instrument drifts cut away.

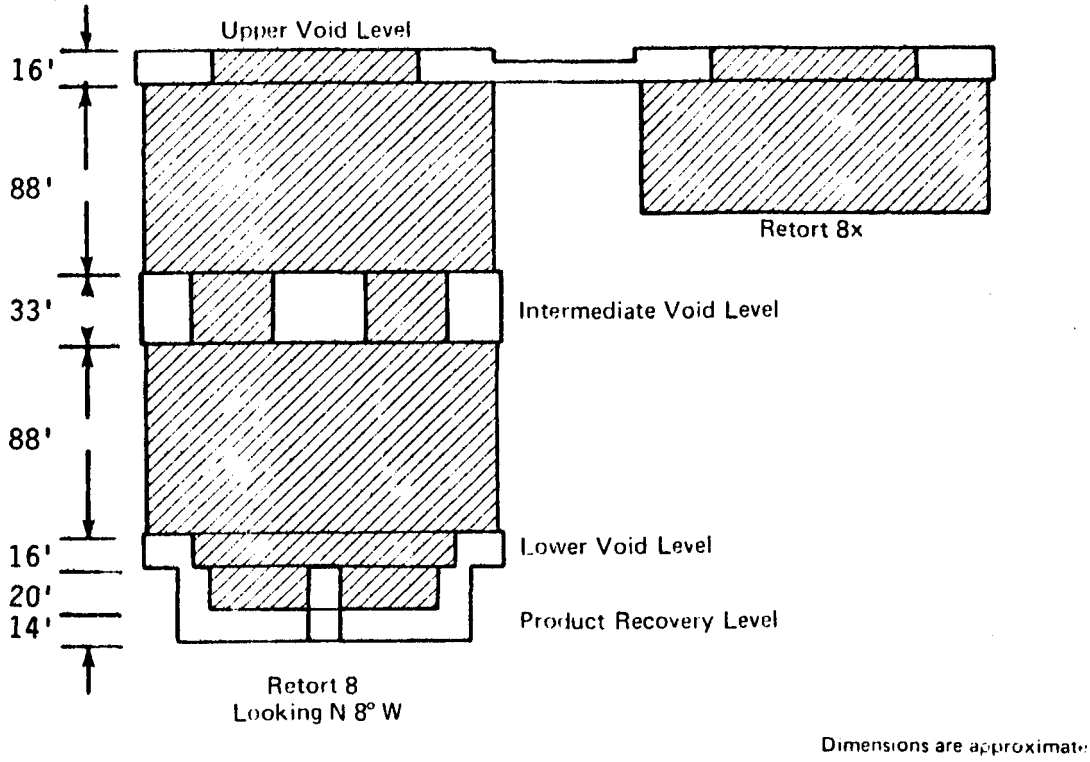


Figure 2. Retorts 8 and 8X design configuration, vertical section. The cut for this section is taken through the retort centerline.

A. RUBBLING

Three retorts were rubbled during the second year of Phase II of the Agreement and a fourth under the OOSI-Funded Rock Fragmentation Program. Retort 8X, a partial retort, was rubbled at 8:17 a.m., Saturday, January 24, 1981. Rubbling of Retorts 7 and 8 took place within the following ten weeks: R7 at 9 a.m. Saturday, February 21, and R8 at 9:25 a.m., Saturday, April 4. The OOSI-funded Mini-Retort 4 rubbling was at 4:45 p.m. Friday, June 13, 1980.

For each shot, preblast and postblast surveys were conducted, areas underground were photographed after the blast, and data from the various monitors were analyzed. The schedule for loading blast holes and a description of other pre-blast activities, including precautions taken to protect equipment, personnel, and systems in the mine during rubbling, are presented in the Quarterly Progress Report for the period December 1980 through February 1981.

Overall it appeared that the four blasts went as expected except for: the ignition of blast gases which occurred four minutes and 45 seconds after the R7 blast on the Upper Level only; and damage to the R8 center drawhole which was found when the Product Level was cleaned after the blast. The assumed explanation for the ignition was that detonation products from the blast were ignited by electrical equipment in the mine maintenance shop and the resulting flash fire followed the blast fumes to the upper entry of R7. At that location several small stable fires occurred on loose shale, placed in the upper entry to R7 to contain fly rock during detonation. The mine resumed normal operation after the loose shale was removed from the mine and those pieces that were burning were quenched with water.

The R8 center drawhole was badly fractured during the rubbling with voids and/or broken rock surrounding the drawhole liner. In order to stabilize the area, spiling was driven under this drawhole and two steel sets were installed. Four steel sets were installed

behind the center pipe under R8 and caught up over the sets and around the pipe. After all the steel supports are in place, concrete will be injected around the drawhole liner.

Retort 8X was a partial retort, and therefore was rubbled by blasting into one horizontal room located at the R7, R8, and R8X Upper Level. R7 and R8 were rubbled by blasting into three horizontal rooms with about equal amounts of rock expanded upward and downward into the rooms. The pillars located in each room were blasted first, giving the rock between the void levels free faces toward which to expand. After blasting, the horizontal layers of shale appear almost as intact as they do prior to a blast except that there are extensive crack networks, vertical and horizontal, throughout the formation. These provide the paths for the air flow needed to process the retorts. Only the shale at the free face and the pillar rubble experience total disruption and rotation.

Excellent reproducibility for a large-scale blasting operation can be noted in comparisons of R7 and R8. The average void height above R7 is 14.95 feet; above R8, 14.62 feet. The void in R7 is 407,200 cu.ft.; in R8, 374,100 cu.ft. Though not as smooth and flat as R7, the rubble pile in R8 is still excellent. The roofs in both retorts are very competent and did not fall in either retort.

Initially developed as a two-level retort, MR4 was changed to a three-level retort during the third quarter last year to study edge effects for the three-level Retorts 7 and 8 design. The post shot survey and photographs of the top of the rubble pile showed that the rubble pile was fairly flat and the void above the pile was approximately five feet, as anticipated.

B. MINING

The mining activity to access and mine the voids for Retorts 7, 8, and 8X and the Mini-Retorts began in August 1979 and was completed

in December 1980. A number of statistics were compiled for this effort. These statistics are:

Labor expended		157,100	manhours
Shale mined (including raise boring)		463,000	tons
Drift footage		6,000	feet
Mining:	Rockbolts installed	29,100	rockbolts
	Wire mesh installed	288,600	sq. ft.
	Ventilation tubing hung	20,700	feet
	Utility pipe hung	15,500	feet
Drilling		639,100	feet

More than 192,000 tons of rock were removed for R7, 8 and 8X development from May through December 1980. Table I shows the mining purpose, cross-section dimensions, feet of advancement and tons of rock removed.

Mining work to access and create the voids for Retorts 7, 8, and 8X progressed 4,734 feet during the period June through August and 5,136 feet (107,885 tons of shale removed) from September through November. Upper and Lower Level voids were completed by the end of November and Intermediate Level voids were completed in December, as illustrated in Figures 3, 4 and 5. During the quarter December 1980 through February 1981 mining progress totaled 897.5 feet advance (21,820 tons of shale removed). By the end of December, product raise drilling was complete in the R8 Lower Level, work was complete on scaling, cleaning out the room and drilling pillars in the R8 Intermediate Level, and ventilation was installed at the R8 Upper Level. With mining activities to access and mine the voids completed in December, the next several months were spent preparing to rubble the retorts, preparing for instrumentation testing, and in cleanup operations following the three retort rubbling blasts.

During January, rock bolting in the product drifts under R7 and wire meshing of product drifts under R7 and 8 were completed. On the Upper Level, three cutouts for water monitoring in the U-500

TABLE I

SUMMARY OF MINING PROGRESS
Phase II - June 1 through December 31, 1980

HEADING	PURPOSE	CROSS SECTION (feet)	ADVANCE (feet)	TONS REMOVED
LOWER LEVEL:				
L-1745-E	R8 access	16x16	70	1,255
L-1	Sump	15x13	13	178
L-1770-E	R7 & 8 connecting drift	14x14	155	2,126
R7	Void	14x14	54	741
		44x14	116	4,903
		20x14	38	745
		30x14	95	2,793
	Slabbing	18x13	10	—
		6x14	12	—
R8	Void	16x15	79	1,327
		18x15	77	1,455
		34x15	144	5,141
		30x15	122	3,842
		45x15	213	10,064
	Pillar slabbing	6x16	480	—
1230	Lunch Room	10x16	10	112
		LOWER LEVEL TOTAL		34,682
INTERMEDIATE LEVEL:				
L-1240-E	Substation	15x15	20	315
	Extension	20x18	81	2,041
L-260-N	Slabbing	14x14	46	—
L-661-N	Instrument drift	20x18	215	528
Ore pass	Raise	8x8	92	412
R7	Access	16x16	80	1,434
	Void	25x17	51	1,517
		44x17	510	26,704
		26x15	308	8,408
		28x18	80	2,822
		3.5x17	45	187
		7x17	330	2,749
		25x12	212	4,452
		7x25	165	2,021
	Slabbing	16x 5	102	—
	Vent drift	8x 8	57	255
	Raise	8x 8	25	112

TABLE I (continued)
SUMMARY OF MINING PROGRESS

HEADING	PURPOSE	CROSS SECTION (feet)	ADVANCE (feet)	TONS REMOVED
INTERMEDIATE LEVEL: (continued)				
R8	Access	16x16	91	1,631
	Void	18x16	285	5,746
		45x17	96	5,141
		25x18	52	1,638
		44x17	94	4,922
		25x16	347	9,716
		3.5x16	256	1,003
		12x25	256	5,376
		12x44	116	4,287
		6x25	104	1,092
	Slabbing	44x21	70	—
		—	—	3,514
	Vent drift	8x 8	74	332
	Raise	6x 6	25	63
	Other	—	—	5,523
			INTERMEDIATE LEVEL TOTAL	103,941
UPPER LEVEL:				
U-660-N	Instrument drift	18x16	22	444
U-370-N	Instr. drift slabbing	18x18	21	—
Pillar	Test area	15x12	18	227
R7	Pillar slabbing	16x 5	433	—
	Slabbing	18x 5	392	—
R8	Void	33x16	369	13,638
		33x17	112	4,398
		5x17	265	1,577
	Slabbing	5x16	302	—
		13x17	166	—
R8X	Access	16x16	85	1,523
	Void	18x16	376	7,580
		30x16	63	2,117
		34x16	206	7,845
	Slabbing	16x13	78)	
		18x 5	26)	5,496
		5x17	452)	
		13x16	138)	
			UPPER LEVEL TOTAL	44,845

TABLE I (continued)
SUMMARY OF MINING PROGRESS

HEADING	PURPOSE	CROSS SECTION (feet)	ADVANCE (feet)	TONS REMOVED
PRODUCT RECOVERY LEVEL:				
R7	Drifting	14x14	200	2,744
	Drifting	14x15	139	2,043
	Drifting, left & right	14x15	101	1,486
L-1430-L		14x14	12	165
L-1430-R		14x14	12	165
S. Draw Pocket		9'Dia.	20	89
R8	Drift	14x14	17.5	240
	Drift, left & right	14x15	122	1,793
			PRODUCT RECOVERY LEVEL TOTAL	8,725
			TOTAL MINING PROGRESS	192,193

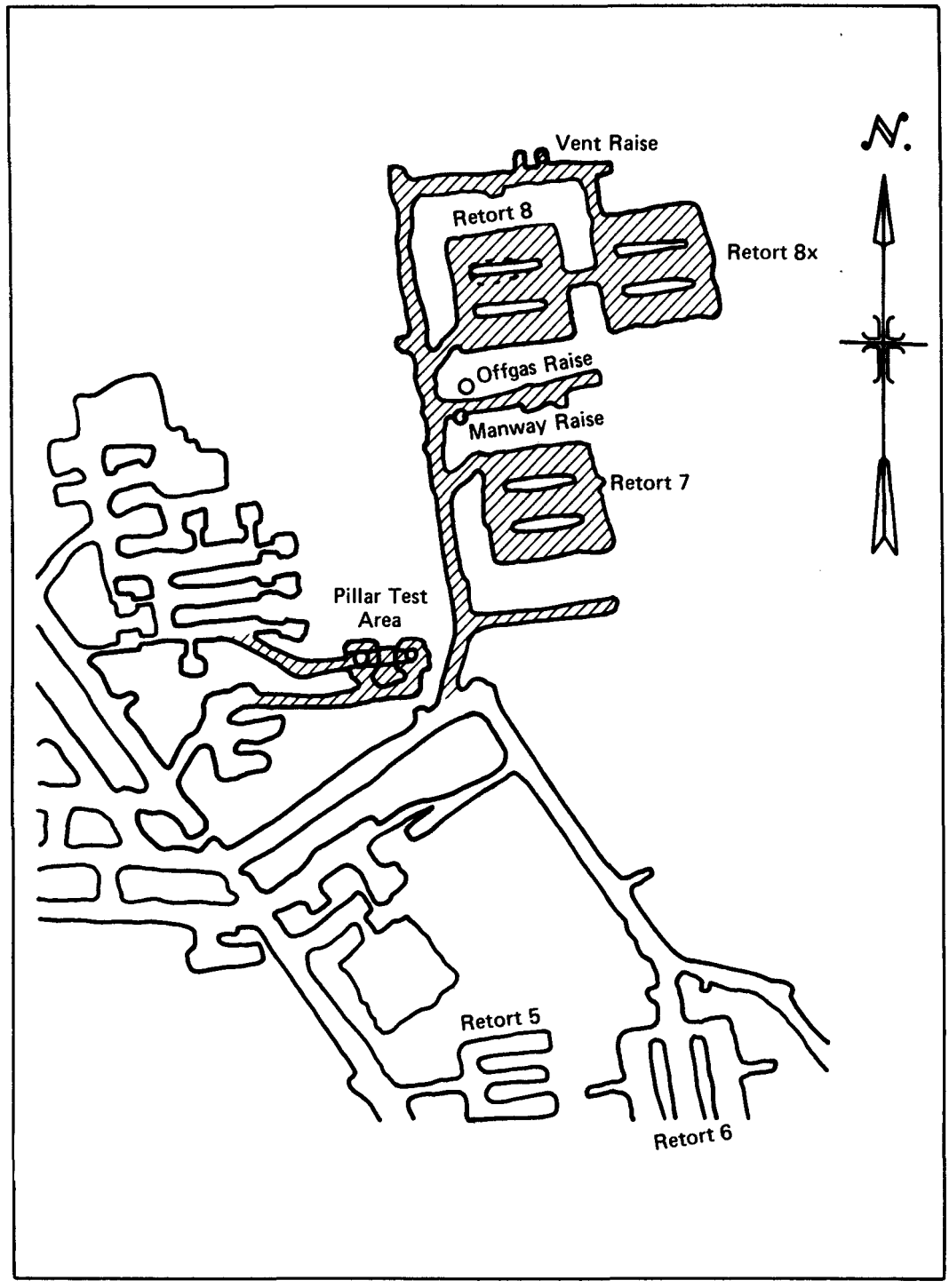


Figure 3. Retorts 7 and 8 Upper Level access and void mining progress through November 1980.

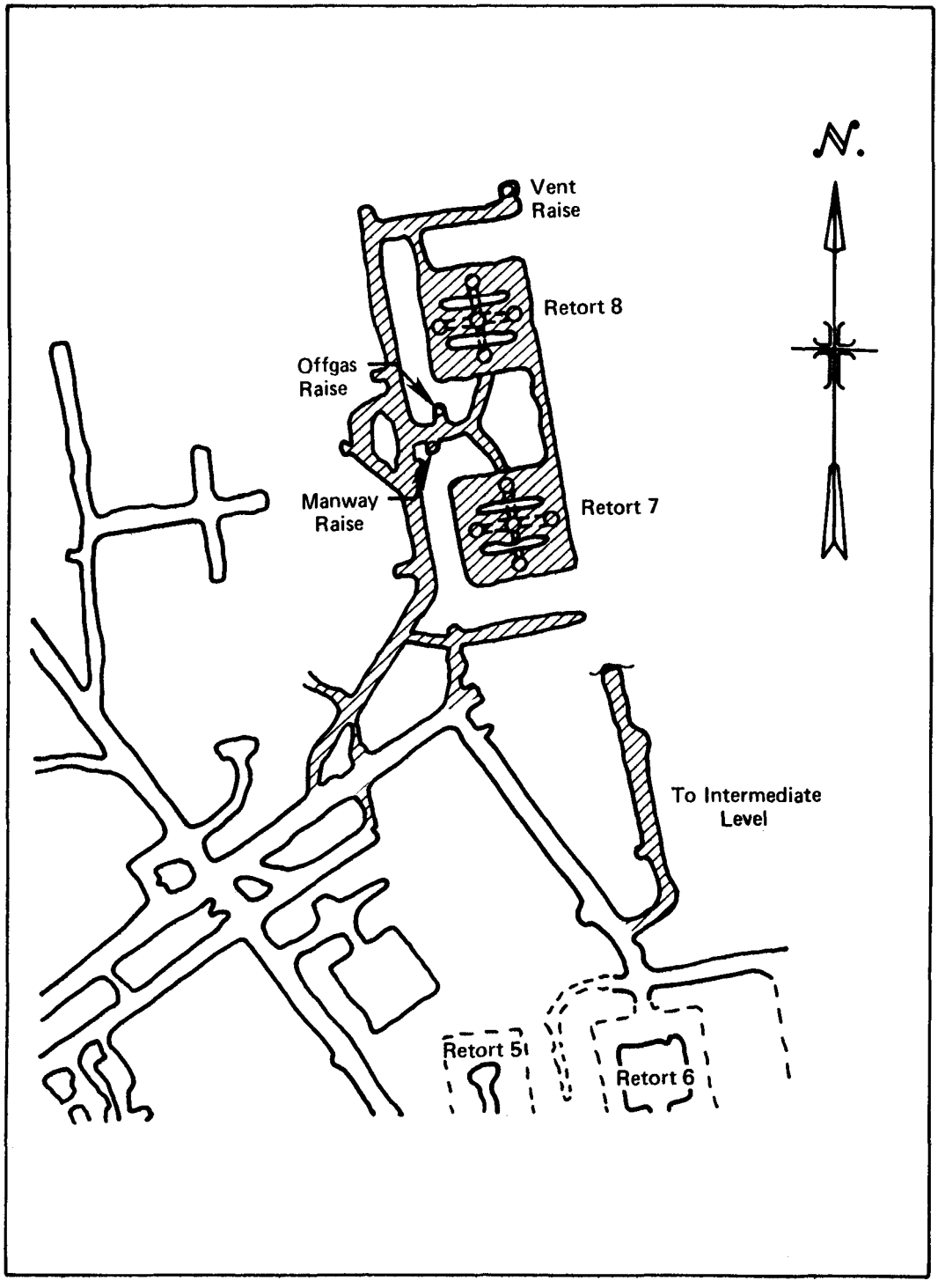


Figure 4. Retorts 7 and 8 Lower and Product Level access and void mining progress through November 1980.

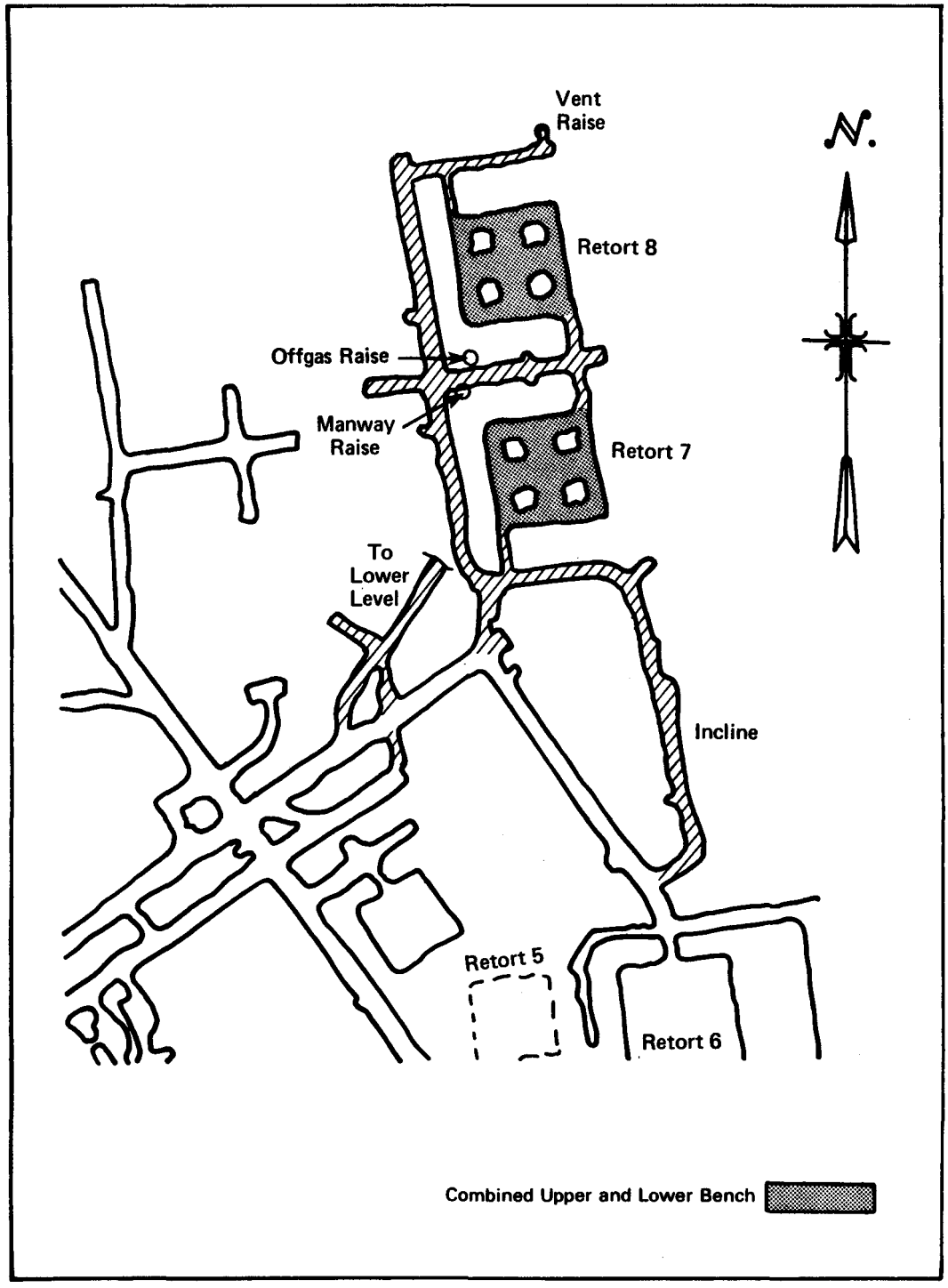


Figure 5. Retorts 7 and 8 Intermediate Level access and void mining progress through December 1980.

drift were rock bolted and wire meshed, and blast holes in R7 were cleaned. Advances and muck removal in January took place in the Upper Level instrument drift, at high frequency electromagnetic mapping (HFEM) and water monitoring hole stations, at the Lower Level instrument drift, at three raises shot through the Lower Level from the bottom of R8 into the Product Level, and also at two cut-outs shot for Upper Level water monitoring stations. During February, muck removal was at the Upper Level of R8X after the rubbling blast, at Intermediate Level R7 and 8, and in drifting at Lower Level, L-70. Other mining activities included installing rockbolts, wire mesh, ventilation tubing and utility pipe.

By the final quarter (March through May) Retorts R8X and 7 had been blasted and mining activities in March were concentrated on preparations to shoot R8 in April. Retort 8 was rubbled on April 4 and work then centered on clean-up, cutouts for the hot inert gas generator (HIGG) and drift work. In May the emphasis turned to completion of the slots for bulkhead construction and beginning thermocouple hole drilling. Repairs were made to the timbers at the Research Mine portal, and instrument holes were pumped for Occidental Research Center's high frequency electromagnetic mapping (HFEM).

At R7, four steel sets were put under the brows near the drawholes in the product drifts, and at the R7 and 8 entrances on the Upper Level, rock bolting and wire meshing were completed. Wire mesh also was installed along the ribs at the intersection under R7 at the Product Level. Under the center drawhole of R8 spiling was driven and two steel sets were installed. Four steel sets were installed beyond the center pipe under R8 and caught up over the sets and around the pipe. The straight-away to the northernmost raise under R8 now is open. Seventy-five feet of ventilation tubing for the exhaust system from the steam and lube shop have been installed.

Sand membrane installation between Retorts 8 and 8X was completed, and one slot was shot in the back between Retorts 8 and 8X and another for the bulkhead at the entrance to R8X on the Upper Level. Refractory plates were installed at the entrance to R8X on the Upper Level, and with the installation of rock bolts in the bulkhead location at the R8X entrance from the U-660 drift, the mining work was completed on the bulkhead at R8X.

The drift work in May includes:

- U-370 drift--scaled and cleaned to prepare the area for ORC to work.
- L-662 drift--grouted thermocouple casing in holes drilled from the drift.
- U-660 drift--pumped HFEM holes in the drift.
- U-1000 drift--completed scaling in the drift.
- L-1240 incline--completed scaling in the incline.

C. DRILLING

Drilling of R7 Upper Level and R8X blastholes was completed during the quarter September through November. Blasthole drilling at the R8 Upper Level began in November, surface burner hole drilling started in late November and blasthole drilling at the R7 Intermediate Level began in December.

During the quarter December 1980 through February 1981, 23,057 feet were drilled including work at the R8 Intermediate Level throughout the quarter. The total also includes drilling at the R8 Upper Level, R7 Upper and Intermediate levels, R8X instrument core holes, and a Mini Retort 3 (MR3) instrument hole, plus drilling seismic, burner, blast, utility, and core holes.

More than 16,000 feet were drilled during the quarter March through May, including:

- underground water sampling holes . . . . . 718 ft.
- a third HFEM hole in U-370 drift . . . . . 292 ft.

- water monitoring holes, Lower level R8--near periphery . . . . . 513 ft.
- blastholes cleaned, R8 and MR1 in Research Mine . 2140 ft.
- underground hole for USBM . . . . . 124 ft.
- water well hole at L-1 portal . . . . . 299 ft.
- thermocouple holes underground . . . . . 5926 ft.
- Surface air injection holes to R7 and 8 . . . . . 5360 ft.

  Thirty-two holes drilled

  Twenty-nine of the holes cased

  Seventeen of the holes grouted

  One surface thermocouple hole on R8 completed

  Grout drilled from the holes
- HFEM holes in U-660 and core hole between R8 and 8X . . . . . 381 ft.

Other drilling in the final quarter was done for holes at the U-660-N, U-1000, Upper Level of R8, entrance to R8X; blastholes for R8, a third sand hole for the bulkhead in the Product Level drift between R7 and 8, two 10-inch utility holes from U-1000 drift to the L-1240 drift on the Intermediate Level, HFEM 660-N and 230-N, and coring was drilled for the U. S. Bureau of Mines. Also six holes with an air track for sample tap pipes have been drilled: two from the L-910 drift, and four from the L-260 drift.

D. CONSTRUCTION

1. Mini-Retort Area

Construction efforts this year at the Mini-Retort area were spent in preparation for the MR3 burner ignition tests conducted in November, the MR4 ignition tests in January, and a second start-up test of MR3 at the end of April.

During the quarter June through August, bulkheads were installed and shotcreted at the MR3 intermediate level and the MR4 lower and intermediate levels. Distribution piping at the

upper level of each MR was completed. In September, the major construction work for MR3 was completed. The air level bulkhead was shotcreted and the steam and fuel lines were hooked up. Work on other utilities and instrumentation for start-up continued into October.

On MR4, the piping, electrical and instrument designs were completed early in November and construction began. The intermediate level drift was cleaned and readied for the burner foundation, and work continued on installation of the air, steam, water and fuel utility piping on the upper and intermediate levels. Also during the quarter September through November, the inert gas generator discharge piping was installed in the intermediate level. Piping and electrical work also was completed this quarter. The quarter December 1980 through February 1981, the inert gas generator was installed at MR4 and the piping for combustion air, steam, water, and fuel was commissioned.

The MR3 construction work was 50 per cent complete by mid-March and progress continued on preparations to reinstall the Foster-Miller burner which was expected on site by March 27. The construction for the second MR3 burner test was completed in April.

2. Underground R7 and 8

Underground in June, the 4160-volt main mine electrical feeder was tied into the Upper Level substation and the temporary cable supplying power from the Product Level was removed. The concrete foundation for the Intermediate Level substation was poured and the station installed, completing the main mine power system. (The underground electrical conduits were completed in September). Mine air compressor hookup and ventilation fan relocations proceeded in August. Midway into

the quarter June through August, the ore pass chute from the Intermediate Level to the Product Level of the mine, near R7 and 8, was constructed. The grizzly on the ore pass was completed in mid-August.

Underground construction continued in the quarter December 1980 through February 1981 with activities to complete the drawholes for R7 and 8 and to repair various air stoppages and air doors. Support was supplied for retort blast preparations through fabricating flash bulb assemblies, restringing instrument cable, providing electrical services, and completing the underground emergency power system. In May, the R7 and 8, bulkhead construction started.

3. Research Mine

The quarter June through August the cables from the MR area to Sandia's B-61 trailer were hung and site preparation at the Research Mine portal was completed for the trailer.

4. Surface Facilities

Figure 6 illustrates the location of the buildings on the surface in relation to Retorts 7 and 8 underground.

a. Blower Building

The excavation for the Blower Building and the sub-grading for the associated offgas piping trench and blower foundation, and the blower suction pit floor, and nine foundations for the blowers were completed during the quarter June through August.

During the quarter September through November the Blower Building was framed and siding work began. The pad for a

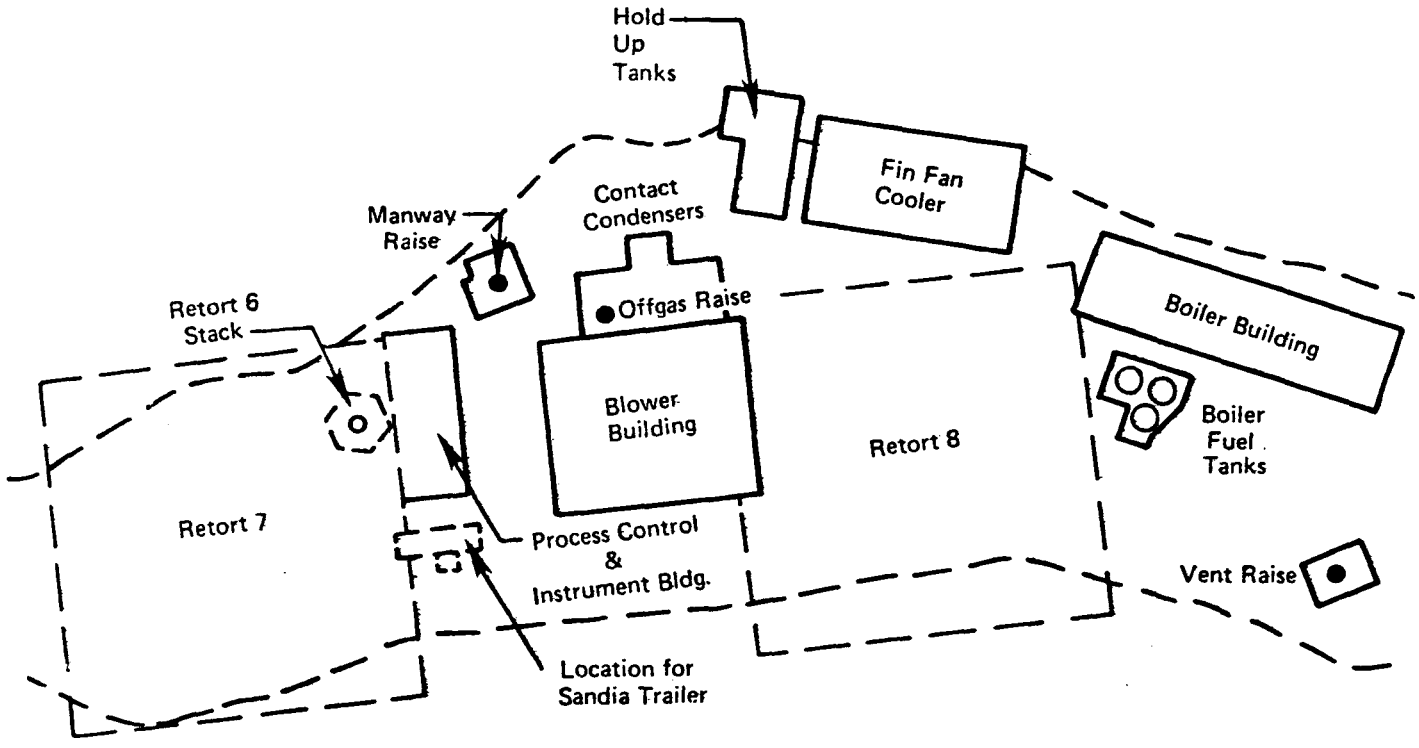


Figure 6. Plot plan of the surface facilities for Phase II showing the building locations in relation to Retorts 7 and 8 underground. The dotted lines on the perimeter indicate where the mountain top drops off sharply.

1500-KVA transformer at the building was formed and poured.

In December, blower installation and the Motor Control Center (MCC) were started; all the major switch gear were installed; 60 per cent of the large diameter prefabricated piping and 50 per cent of the valves were received. In January, the low-voltage MCC was completed and the medium-voltage MCC was begun: large diameter pipe inside the building was erected; eight of nine process blowers were installed; pipe supports inside the building were started; and blower motors were serviced. In February, pads for the pipe support stanchions were poured; blower offgas and fresh air piping was installed inside the building; silencers were modified; and conduit was run from the MCC's to the blowers.

During March, the remaining blower in the Blower Building and a condensate tank in the Blower Building pit were installed, and the forms were built for the blower grouting. Additional stanchions for the main pipe bridge in the blower area were erected; the 500-KVA transformer was hooked up in the building; conduit installation began for blower instrumentation; all roof penetrations for the building were completed; and work continued on the pit grating, the lighting, the electrical for blowers and motor control centers, the offgas, condensate, boiler, and fresh-air piping, and the building grounding tie-ins.

In April, energizing of the low and medium voltage switchgear in the Blower Building was accomplished; installation of instrument conduit in the building was started; grating was 90 per cent complete; work continued to install wire and conduit for the building; and the blower oiling system was started.

By the end of the year the piping inside the building had been completed, electrical work on the blowers was in the final stages, and finishing work continued on the building.

b. Contact Condensers

Rebuilding of the Retort 6 contact condenser for the use on Retorts 7 and 8 was completed in June 1980. The pipe stanchions were fabricated and the foundation for the condensers was poured. Then, in late August, erection of pipe stanchions started. The 7-foot diameter contact condenser was received in October and set in place, and the 12-foot contact condenser arrived on site in mid-November and was set in place. Platforms for the two condensers were installed by the end of November. The small diameter piping was prefabricated in December in the contact condenser area, and during January the internal packing was installed for the contact condenser columns. The electrical panel was set for area lighting. By the end of the quarter December 1980 through February 1981, piping runs for the contact condenser were nearly completed. Area lighting and piping to the 7-foot and 12-foot contact condenser pumps were completed in March and condensate hold up tanks were placed on their foundations. The contact condenser piping to the pumps was completed in April.

c. Boiler Building

Boiler Building foundations were poured the first quarter: Boiler #2 was moved to the surface and Boiler #3 was received and set in place. From September through November, the boiler foundation was poured, the boiler building was framed, insulated and sided; pre-fabricated piping for Boiler #2 was installed; and 11 pipe stanchions and interconnecting steel were erected. By the end of

January, the boiler building (last of the surface buildings) was commissioned and the trench and foundations, and the floor were finished. In February, work consisted of fabricating pipes for the two boilers in the building. During March, the foundation for the pipe bridge extension to the Boiler Building was poured, stanchions were erected, piping was installed, control room progress continued, the Boiler Building lab was started, and electrical work began for the building. Continuing in April was work on the laboratory, erection and fabrication of 2-inch and 4-inch piping (50% complete), and projects for utility wiring, electrical conduit, and fixtures. Electrical work for the Boiler Building continued in May.

d. Vent Raise Building

The foundations for the Vent Raise Building were formed and poured during the quarter June through August and the building itself was completed in mid-August. Installation of the motor control center for the vent raise fans in the building was started that quarter and completed during the quarter September through November. The building was then commissioned.

e. Fin-Fan Cooler and Hold-up Tank

In January, the Fin-Fan Cooler foundation was formed and poured and the hold-up tank area was excavated and back-filled. By the end of the quarter December 1980 through February 1981, the hold-up tank ground wiring had been pulled and tied in, the foundation for the tanks had been poured, and erecting of the Fin-Fan Coolers had begun. All Fin-Fan Coolers were installed by the end of March; conduit had been run to the fin-fan coolers, and grounding was completed. Fin-Fan Area lighting, power, and control wiring were completed in April. By the end of the year,

work was 95 per cent finished on the Fin-Fan Cooler piping and work continued on fin-fan instrumentation.

f. Other Building

Foundations for the Process Control, Switchgear, and Generator buildings were formed and poured in the quarter June through August, and each had framing erected, interior and exterior walls and roofs installed. By the quarter September through November the Generator Building was commissioned and generator switchgear was mounted in the building in September. Two total mine power outages were used in mid-October and late November to energize the surface main switchgear and the main underground 4160-volt power system.

5. Heater Treater

The foundation for an additional heater treater unit was poured during the quarter June through August and the electrical grounding of the Heater Treater area was completed. In September, the new C. E. Natco Heater Treater was received and installed on its foundation. In October, pipe supports were poured. The designs of the tank foundations for a new 2,000-barrel product tank and coalesced water tank were completed. Also during the quarter September through November, the field-constructed 2,000-barrel product tank at the Heater Treater was built. Piping, electrical, and tank installation was underway during the quarter December 1980 through February 1981. Piping fabrication and installation continued during March and work started on area lighting at the Heater Treater. In April, work continued on tank, pump, and equipment grounding. Work on the piping at the Heater Treater continued during May.

6. Lower Mine Bench

A Vending Machine Building at the lower mine bench was completed during the quarter December 1980 through February 1981.

7. Guard Gate

The Security Trailer at the Guard Gate facility was renovated during the quarter December 1980 through February 1981.

8. Other Construction Activities

June through August:

- Completed road improvement of the surface access road. Installed culverts, scaled banks and completed the final grading.
- Installed electrical grounding for all the main structures on the surface. The offgas stack was grounded previously.
- Completed installation of two 200-HP ventilation fans on the surface manway raise.

September through November:

- Removed an abandoned electrical line, including the poles, on the surface.

December 1980 through February 1981:

- Moved the 200-HP fans to the vent raise.

March through May:

- Prefabricated and installed the downhole utility pipe.
- Moved the 1500-KVA transformer from underground to the surface and installed it.
- Installed wire and conduit for the low- and medium-voltage surface electrical system.
- Completed the 54-inch offgas piping and tie-in to the stack ; the piping "T" supports to R8; all R7 and 8 pipe

support pads; the placement of all fresh air piping, except for 50 feet on the west side of R7 (all R8 field fabricated pipe on the outside stanchions was in place); the horizontal 12-inch pipe runs for R7; and the installation of the lightning protection system for the surface facilities.

- Began work on the bulkheads in the R7 and 8 Intermediate Level and on construction of wellheads, and completed shotcreting of the R8X and 8 Lower Level bulkheads.
- Reinstalled the 4160-volt cables to MV-MCC1.

III. ANALYSES

A. MINI-RETORTS

Conclusions and recommendations obtained from the mini-retort (MR) burner tests are expected to contribute to the successful ignition of Retorts 7 and 8. Two types of burners were selected for testing in the MR start-up tests. The first was a Foster Miller downhole burner used on MR3; the second, a John Zink inert gas generator used on MR4.

The first ignition attempt on MR3 in November 1980 was a failure because of numerous problems with the burner. MR4 burner testing and ignition in January 1981 was successful. MR3 was successfully ignited in April 1981 using an improved downhole burner.

1. Tracer Tests

The tracer test program for MR3 and 4 was designed to characterize the rubble in the two retorts and correlate the state of the rubble to the blasting procedure used; to establish an evaluation procedure which would yield reliable information for R7 and 8; to obtain parameters for use in evaluating pressure drop data; and to establish parameters which would allow for the generation of a performance criteria function for modified in situ (MIS) retorts.

Pressure tests were conducted prior to tracer testing and observed leaks were sealed. The calibration, debugging and indoctrination of the tracer system were conducted and tracer testing commenced after the pretests were determined to be satisfactory.

The tracer tests on MR3 were conducted during the first two weeks in July. The evaluation was based on the expected advance rate of the flame front. A core was obtained from the

center of MR3 and the coring and tracer tests indicated that the retort was rubbled fairly well. It was expected that if conductive and convective heat transfer is considered, the MR3 retort would be reasonably efficient.

In August, tracer testing of MR4 began with sample tube continuity testing. Sample tube discontinuities were indicated and it was determined that inadequate drainage of water from the gas collection piping at the bottom of the retort was the source. With the drainage problem corrected, tracer testing started.

In December, work started to set up equipment for the Occidental Research Center (ORC) and Lawrence Livermore National Laboratory (LLNL) high frequency electromagnetic mapping (HFEM). ORC and LLNL removed their equipment in February and continued their analyses at their headquarters. Their HFEM equipment was used at MR4 for pre-ignition tests on the cold retort and for following the retorting front during ignition and water migration.

During January, Laramie Energy Technology Center (LETC) conducted helium tracer tests at MR4. These will be evaluated to correlate tracer data with temperature data for better understanding of flow characteristics through an operating retort.

When available, data from these tests will be reproduced in a subsequent report and also appear in reports prepared by the performing organizations.

2. MR3 Burner Tests

The testing of the MR3 burners was conducted from November 1 through 5, 1980, as documented in Table II, Operating Summary. Both burners failed mechanically after about 18 hours of

TABLE II

MR3 START-UP TEST OPERATING SUMMARY

Date	Time	Burner No.	Run No.	
11/01/80	1500	1	1	Ignited burner, ran at purge condition.
11/02/80	0912	1	1	Lost cooling water, burner shutdown.
	1525	1	2	Tried to re-ignite burner.
	1600	1	2	Vent valve ruptured. Burner seal damaged. Removed burner.
	2115	2	1	Ignited burner, air flow 170 scfm.
11/03/80	0936			Increased air flow 220 scfm.
	1100			Increased air flow 250 scfm.
	1330			Increased air flow 300 scfm.
	1340			Increased air flow 340 scfm.
	1400			Burner flame out. Interlocked down, burner exhaust to 2200°F.
	1430	2	1	Removed burner 800 scfm air into MR3 ignited rubble E6-01 up to 1059°F F4-01 up to 1382°F Replaced and reinforced water vent valve.
	1560			Shut-off offgas blower, shut-off inlet.
	2000	2	2	Ignited burner. Unstable operation for 15 minutes.
	2125			Removed burner and bottled retort.
11/04/80	Day Shift	2		Added separate water lines (2 - Y4 plastic tubes to seal).
	1840	2	3	Ignited burner, operated about 15 minutes. Venturi temperature to 315°F then down at 68°F.
	1900	2	3	Burner stuck in hole. Maintained 10 scfm through retort.
	Swing Shift	1		Rewelded baffle at top of air venturi.
11/05/80	1450	2	3	Removed burner after soaping downhole offgas flow increased from 60 scfm to 2200 scfm. F5-01 increased from 350°F to approximately 400°F. F4-01 increased from 350°F to approximately 400°F.
	2015	1	3	Ignited burner, unstable condition. Venturi temperature to 405°F. Outlet to 360°F. Shutdown after 15 minutes.
	2135	1	3	Removed burner.
	2200			Offgas blower shutdown. Retort bottled up.

operation on each when high pressure steam formed in the cooling jacket. It was concluded that the burners must be modified to prevent damage from cooling water loss and it was recommended to retest MR3 after Retorts 7 and 8 were rubbled.

It appeared that the back of the retort void began deteriorating somewhere between temperatures of 150° to 300° F. Thermocouples immediately around the burner location were presumed to be fully exposed to the void at the time the burner temperature, during one of the runs, approached 2000°F because the thermocouples showed almost immediate response to the increase. From examination of this data and other thermocouples in the back, it was concluded that an average of one foot of rock in the burner area had fallen into the void.

The Quarterly Progress Report for the period September through November 1980 presents diagrams, tables and a more detailed general discussion of the preliminary results of the MR3 burner tests.

3. MR4 Burner Tests

Ignition of MR4 was begun on January 9, 1981, using an inert gas generator, Figure 7. The burner front was established on January 14 after resolving problems with the ignition transformer, the mine water supply and a combustion air valve. Air and steam then were started through the sill and the burner chamber was shut down and the combustion chamber cooled by maintaining a small air flow from the burner to the retort.

The start-up was very successful. Table III summarizes the start-up operation and Figure 8 shows the oil and water production for the ignition period.

See Quarterly Progress Report for the period December 1980 through February 1981 for thermocouple data, offgas data, an

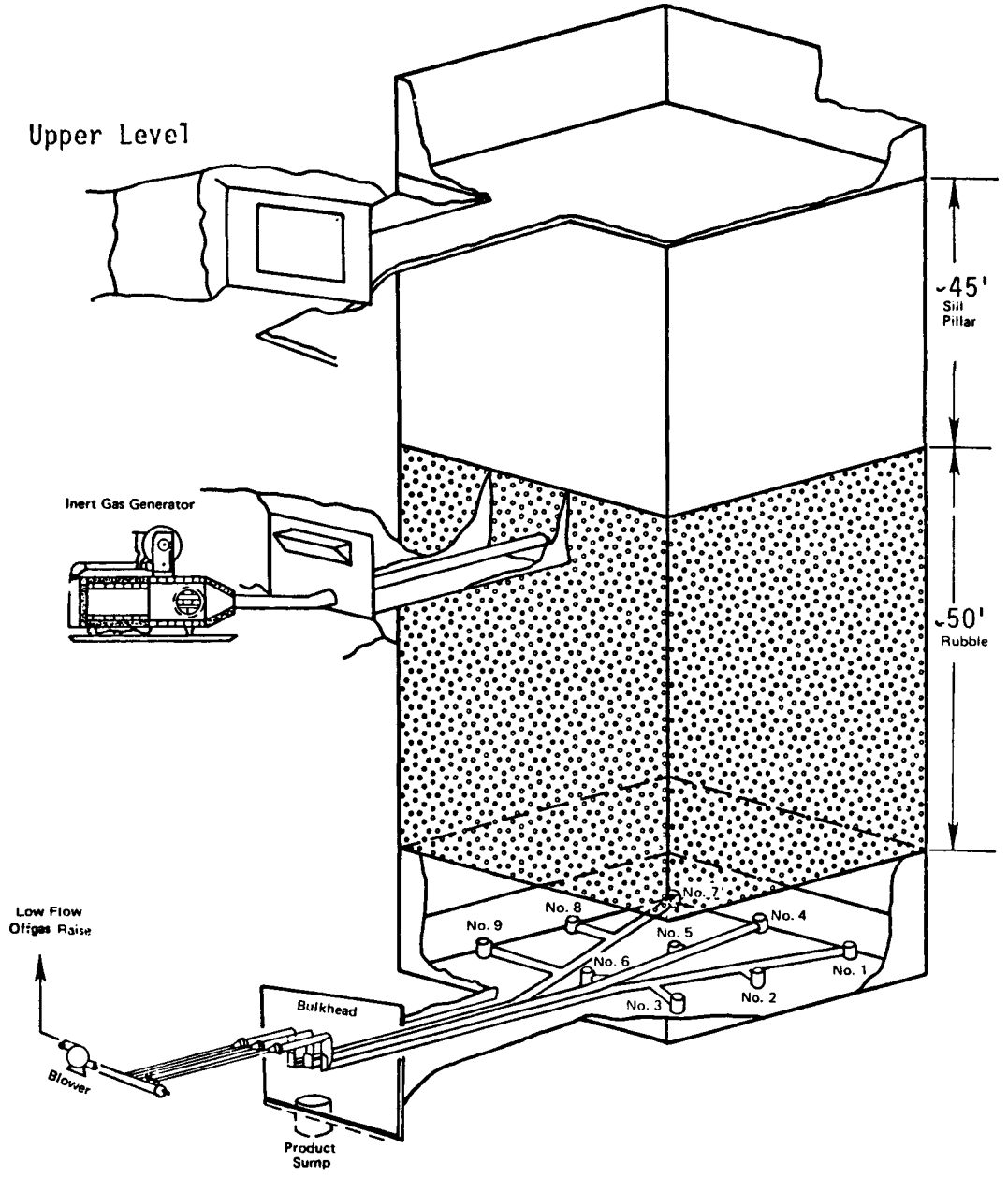


Figure 7. Schematic of Mini-Retort 4 showing the location of the inert gas generator and the product collection piping. Mini-Retort 3 is nearly identical to MR4 in size and product piping. The difference is that the burner used for ignition was placed down a hole from the Upper Level void, through the sill pillar, to the rubble.

TABLE III
MR4 START-UP TEST OPERATING SUMMARY

Date	Time	
1-09-81	1630	Burner checked out
	1730	Started burner - firing rate 1.33 x 10^6 BTU/HR
		Quench water started when gas temperature reached 1100°F
		Flue gas temperature 250 - 300°F
	1800	Excess O_2 at 2 to 4%
1-10-81	0405	Increased burner firing rate to 3.04 x 10^6 BTU/HR
		Offgas O_2 below 2%
	0447	Burner firing rate increased to 4.04 x 10^6 BTU/HR
		Excess O_2 at .68%
	0800	Increased burner firing rate to 5.0 x 10^6 BTU/HR
		Rubble surface temperature = 230°F
	0805	Burner shutdown due to loss of quench water
	1200	Restarted burner
		Firing Rate = 3.8 x 10^6 BTU/HR
	2100	Increased burner firing rate to 5.0 x 10^6 BTU/HR
1-11-81	0800	Offgas O_2 below 1.0%
	1445	Rubble surface temperature = 635°F
	1520	Adjusted burner to allow 2.5% excess O_2
	2330	Adjusted burner to allow 5.4% excess O_2
1-12-81	0430	Increased burner excess O_2 to 7.0%
		Firing rate is 4.34 x 10^6 BTU/HR
	0500	Firing rate changed to 3.66 x 10^6 BTU/HR
		Excess O_2 is 9.52%
	0737	Excess O_2 is 10.2%
		Offgas O_2 is .54%
		Flue gas temperature between 1550 and 1640°F
	1520	Firing rate = 5.24 x 10^6 BTU/HR
1-13-81	0315	Started adding combustion air through sill at a rate of 353 SCFM O_2 in offgas increased to 1.35%
	1315	Firing rate = 5.75 x 10^6 BTU/HR
		Combustion air through burner = 920 SCFM
		Combustion air through sill = 356 SCFM
1-14-81	0100	Firing Rate = 3.6 x 10^6 BTU/HR
		Excess O_2 = 10%
	0900	Increased excess O_2 to 15%
	1230	Burner shutdown - maintained 100 SCFM cooling air through burner
	1840	Steam introduced to sill = 50 SCFM
	2140	Began to adjust offgas blower to bring in 757 SCFM through seal
		Cooling air shutdown
	2222	Steam increased to 320 SCFM

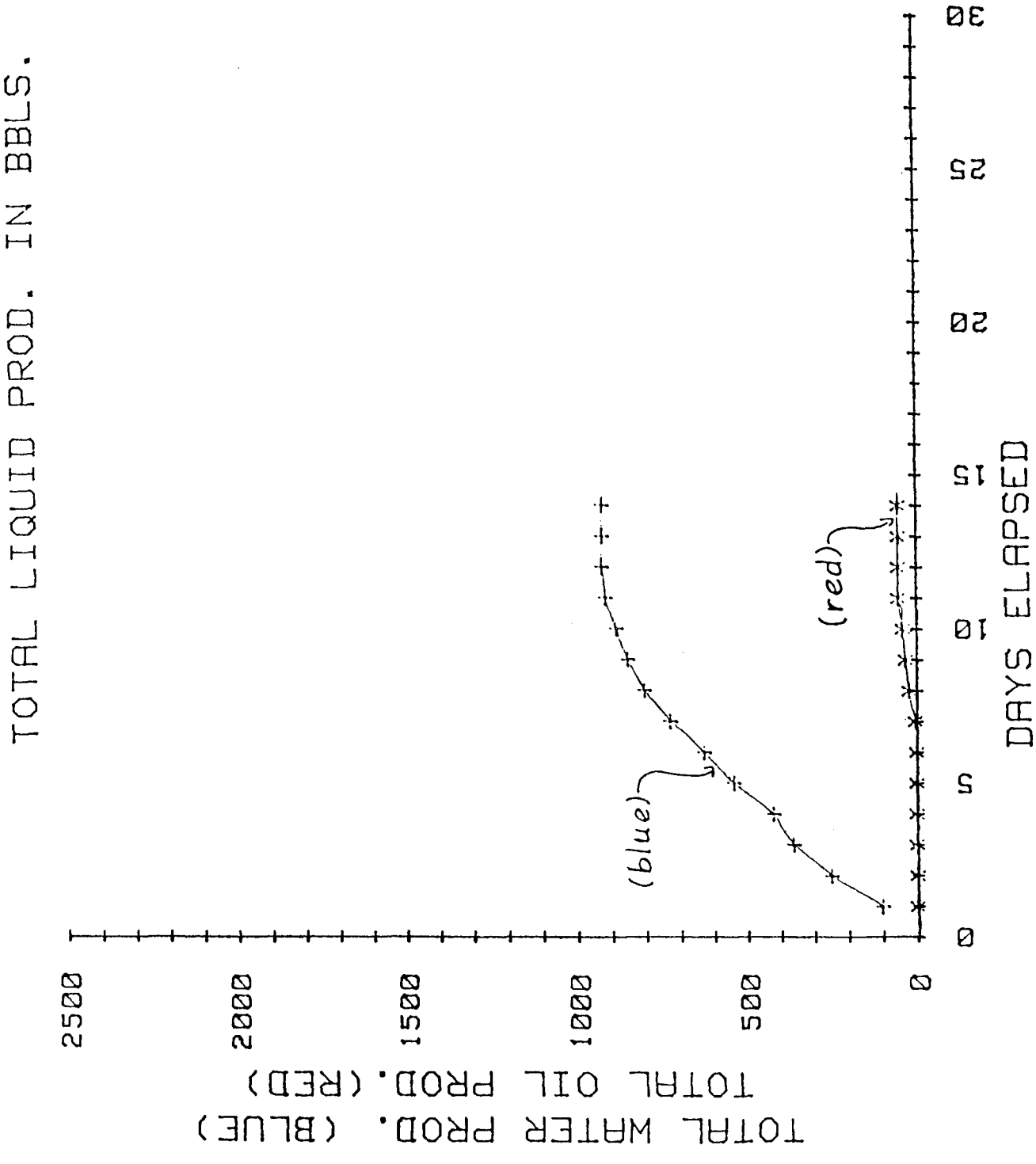


Figure 8. MR4 Oil and Water Production During Start-up.

explanation of the data format, and a process flow diagram for MR4.

4. Preliminary Sandia MR3 and MR4 Ignition Data Analysis

Although MR3 was not ignited, data were obtained for measurements of retort heat-up during burner operation. Figure 9 shows temperature contours for the surface of the rubbled retort and Figure 10 shows temperature profiles for a vertical section from the surface to a depth of 15 feet within the bed. Both figures tend to support the presence of a uniform distribution of bed permeability. See Quarterly Progress Report for the period September through November 1980 for details.

From the start of MR4, the hot inert gas generator (burner) served as an energy source. Figure 11 shows fuel flow versus time (Julian calandar) for the approximate five-day period of burner operation. With the exception of the brief off-time near day 1010.4 (January 10, 9:36 a.m.), the plot indicates relatively stable burner performance. Energy was delivered from the burner at the side of the retort to the space between the back and the surface of the rubble.

5. MR3 Ignition Retest

Retesting of the Foster-Miller Associates downhole burner to ignite MR3 began on April 23, 1981 with the following results:

Thursday	April 23	No. 1 Burner	Ignited, fouled by high water hardness. Installed Culligan water softener.
Friday	April 24	No. 2 Burner	Ignited, burner flamed out at high firing rate.
Saturday	April 25	No. 1 Burner	Ignited, fouled.

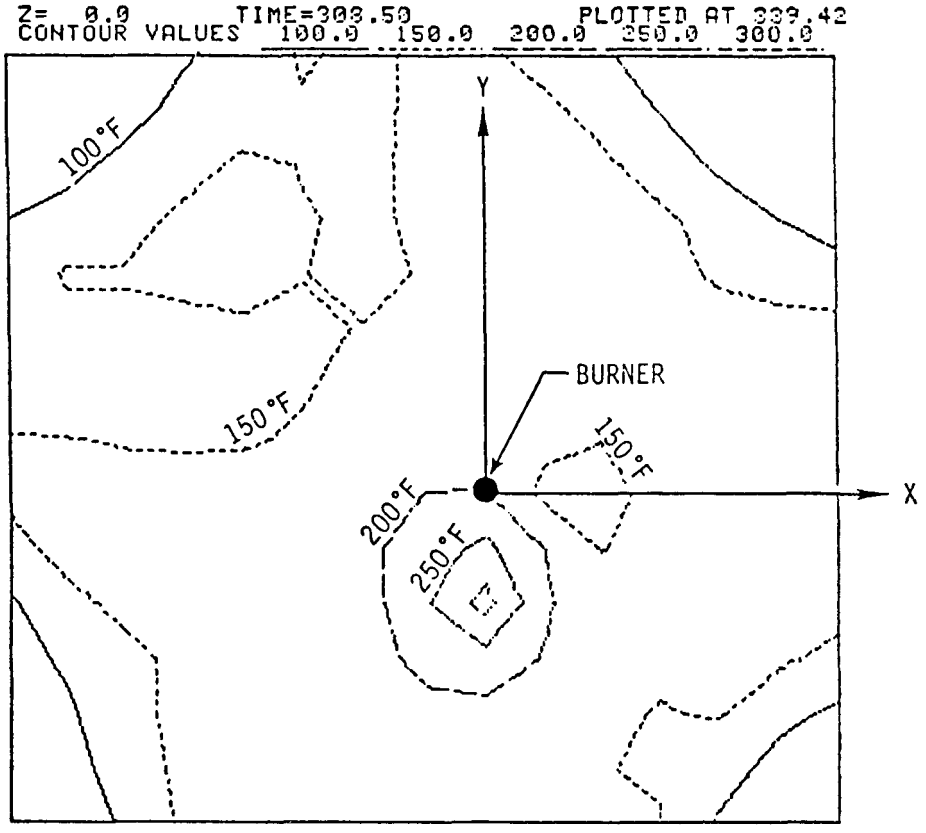


Figure 9. Temperature Contours on the Rubble Surface.

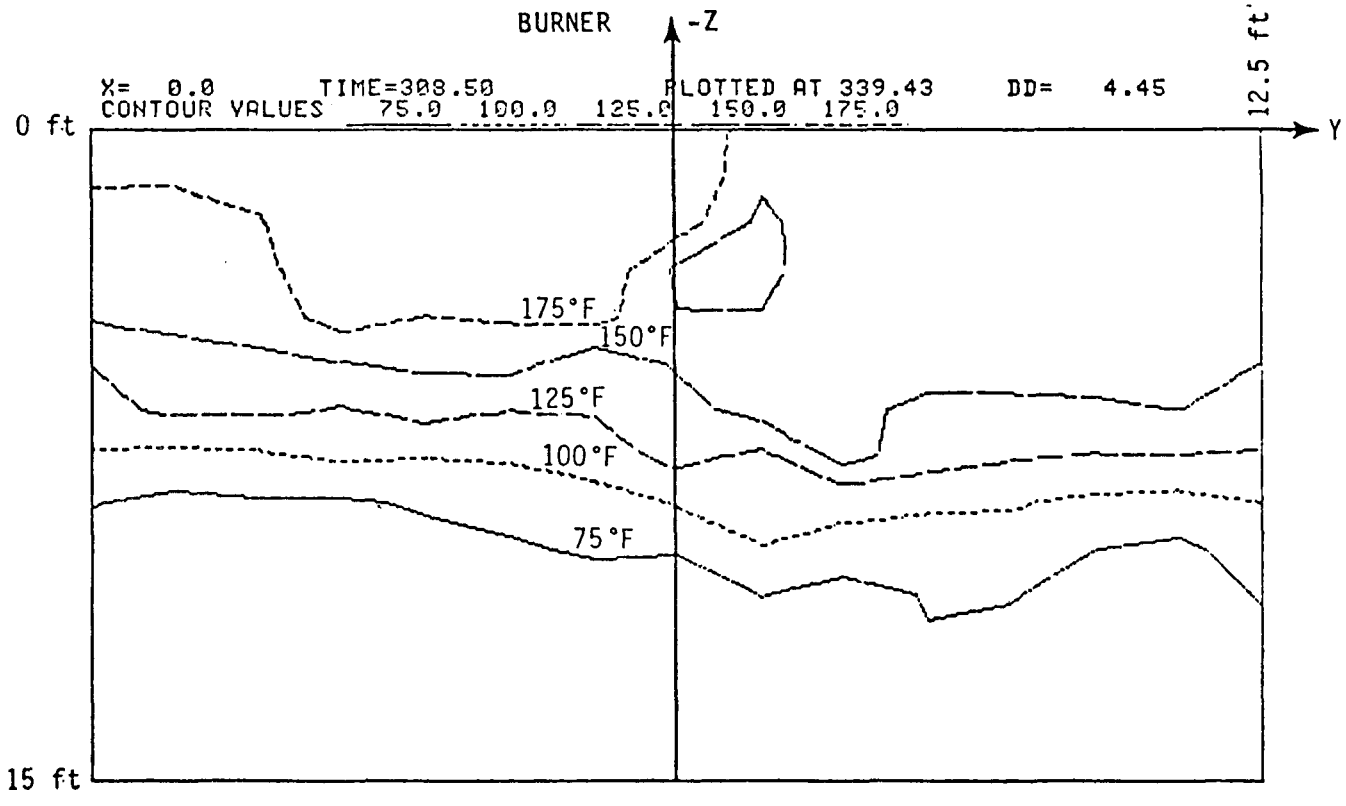


Figure 10. Temperature Contours in the Z-Y Plane.

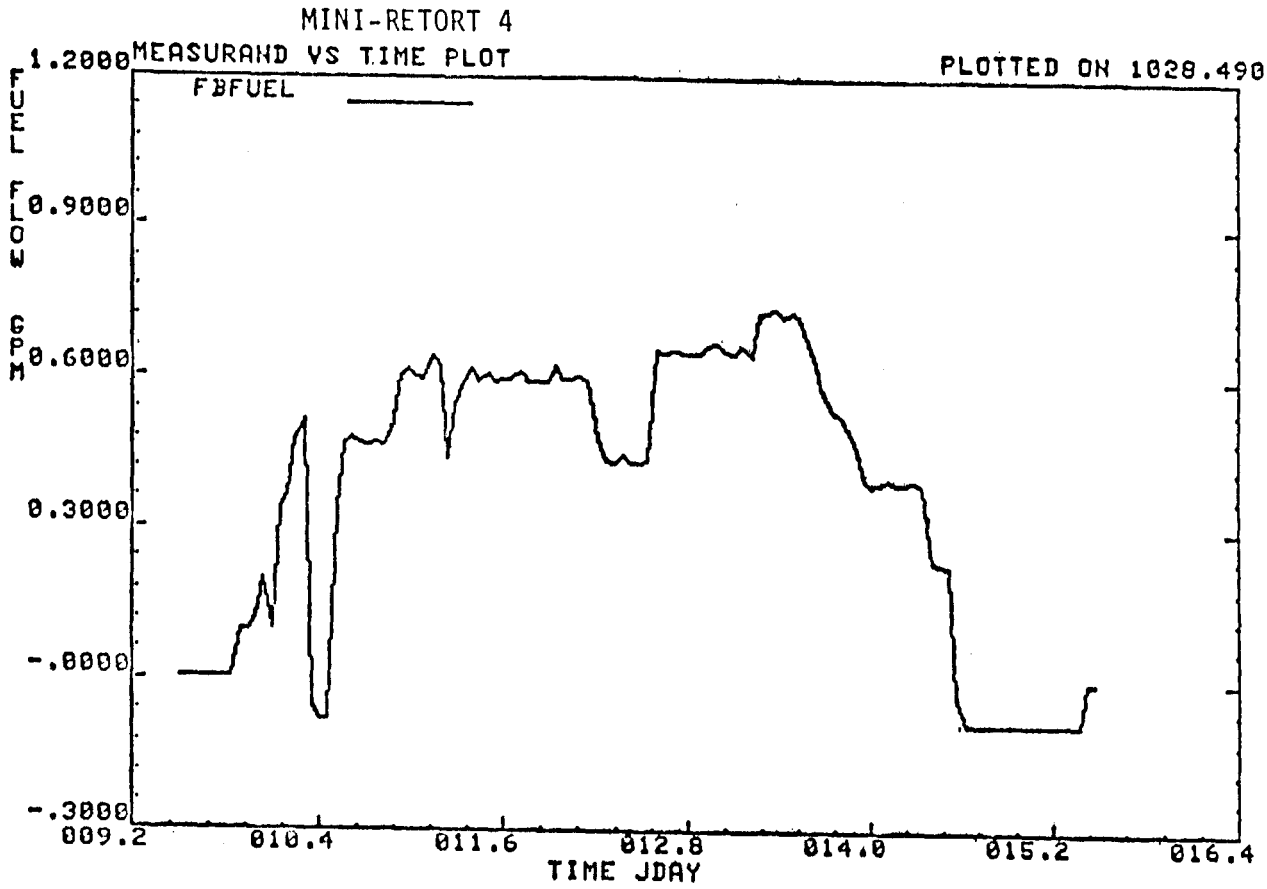


Figure 11. Burner Fuel Flow vs. Time.

Sunday.....April 26....No. 1 Burner....Burner would not ignite.

Monday.....April 27....No. 2 Burner....Ignited, unstable on high firing rate and ceramic liner failed.

Monday,p.m..April 27....No. 1 Burner....Ignited on second attempt.

As can be seen, one burner ignited but was unstable on high firing rate and the ceramic liner failed. The other burner, fouled by high water hardness which was corrected by installation of a Culligan water softner, ignited on the second attempt. The burner ran well until it was shut down and removed on April 29.

Preceding the retest, a detailed plan of ignition with decision points was prepared, the MR3 operation manual and start-up procedure was revised and assembled, and the MR3 burner control panel was placed at the MR3 sill bulkhead. The burner hole was opened to attempt to establish the condition of the void volume above the rubble pile prior to retesting, but the attempted camera inspection was unsuccessful due to lack of sufficient operating space and fogging of the camera lens. A bomb sample taken in preparation for opening up the burner hole showed the gases well below the lower explosive limit (L.E.L.), and no difficulties were experienced during the time the hole was open.

B. RETORTS 7 AND 8 RAW SHALE (CORE)

Results of analyses completed through February 1981 on core LW-156 taken between R7 and 8 have been published. See the Quarterly Progress Report for the period December 1980 through February 1981. These analyses include trace metals and silica determinations by ORC, and ORC performed Fischer Assays, sulfur species and arsenic distribution in Fischer Assay products, carbonate/carbon dioxide,

and minerology on the raw core; Fischer Assay by LETC; and elemental analyses (neutron activation method) by Los Alamos Scientific Laboratory (LASL).

The DOE-LETC borehole TV camera was used in the R7 and 8 area during the first week in August at LW-165 and 166 from the surface to the U-370-N drift. The same camera was run down the MR3 rubble corehole the following week. Determining the scale of what was photographed was difficult and the outer one-third of the pictures was distorted, magnifying cracks and borehole irregularities. Consequently, the borehole TV camera will only be used to locate sections of a borehole that are free of cracks and irregularities. This will facilitate the placement of sensitive equipment such as acoustic emitters/receivers, and packers for hydraulic fracturing and air injection/permeability studies. The camera cannot be used to gain quantitative information.

C. RETORT 6 BALANCES AND OIL INVENTORY

Material, enthalpy, and energy balances covering the start up and operation of Retort 6 have been prepared. A period of 324 days, August 28, 1978, to July 17, 1979, was included. Accumulations of flow data and average stream compositions were used to perform the balances which are given in Figure 12 and Tables IV through VII. A detailed discussion of the balances is given in the Quarterly Progress Report for the period December 1980 through February 1981.

Although Retort 6 was a single retort operation, because its construction was an extension of the existing mine and the operating facilities installed for Retorts 4 and 5, the investment required for R6 was reduced to a level comparable with a multiple retort operation. The overall energy efficiency of R6 was estimated to be 44 per cent, and the estimated external energy consumed to prepare R6 was 1.5 per cent of the energy in-place. For R6 the energy consumed as electricity was 7 per cent of the equivalent energy

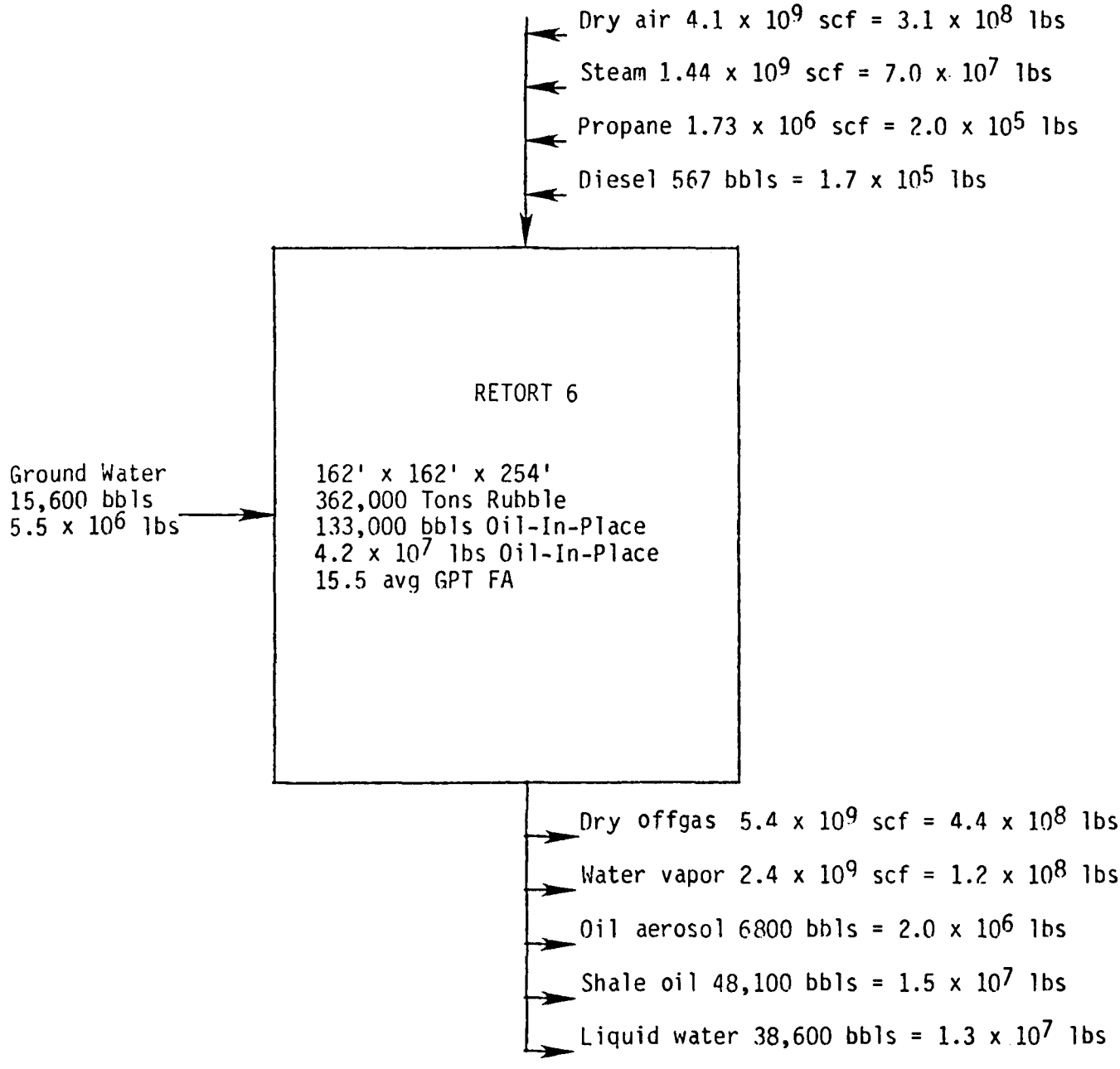


Figure 12. Retort 6 Material Balance: 8/28/78 — 7/17/79.

TABLE IV
AVERAGE COMPOSITION OF RAW SHALE AND PRODUCT STREAM

RETORT 6 AVERAGE RAW OIL SHALE COMPOSITION (Logan Wash cores LW-109 and LW-41)

Fischer Assay Analysis: 15.5 GPT avg FA, 1.4% wt. avg water product

General Analysis:	Organic carbon	7.2 % wt.	Total Sulfur	0.42% wt.
	Hydrogen	1.3 % wt.		
	Nitrogen	0.24 % wt.	Carbonates (as CO_3)	26.3 % wt.
	Organic sulfur	0.075% wt.		
	Ultimate organic composition	8.8 % wt.		
	Inorganic composition	91.2 % wt.		

RETORT 6 AVERAGE PRODUCTION COMPOSITIONS

	DRY OFF-GAS % vol	DRY OFF-GAS % wt.
N_2	59.0	53.0
CO_2	29.8	42.0
H_2	6.4	0.41
CO	1.4	1.3
CH_4	1.3	0.67
Ar	0.7	0.9
O_2	0.7	0.7
C_2H_4	0.09	0.08
C_2H_6	0.2	0.19
C_3H_6	0.06	0.08
C_3H_8	0.09	0.13
C_4^+	0.095	0.18
H_2S	0.138	0.15
COS	0.005	0.01
CS_2	0.001	0.002
CH_4S	0.002	0.003
NH_3	0.58	0.32

WATER VAPOR (CONDENSATE) mg/l (=ppm_v)	
Total alkalinity	25,000
Bicarbonate	19,000
Total hardness	9
Calcium	2
Magnesium	0.2
Chloride	200
Fluoride	0.4
Silica	4
Nitrogen	7,000
Ammonia	6,500
Total sulfur	32
Sulfate	15
Oil & grease	400
Phenol	70

OIL AEROSOL (CONDENSATE) % By Weight	
Carbon	82
Hydrogen	12
Oxygen	1.4
Nitrogen	1.0
Sulfur	0.6
Phenols	1.0
Arsenic	2 ppm
Organic Chloride	6 ppm
Hydrogen Sulfide	<1 ppm
Maleic Anhydride	70 ppm
Paraffins	18.4
Olefins	30.6
Naphthenes	6.1
Aromatics	44.9
BS&W	<0.1

SHALE OIL % By Weight	
Carbon	85
Hydrogen	12
Oxygen	1.4
Nitrogen	1.4
Sulfur	0.6
BS&W	0.15
Arsenic	16 ppm
Hydrogen Sulfide	<1 ppm
Maleic Anhydride	75 ppm

RETORT WATER mg/l (=ppm_v)	
Total alkalinity	8,400
Carbonate	1,600
Bicarbonate	6,800
Calcium	30
Magnesium	20
Sodium	3,500
Silica	30
Chloride	170
Fluoride	40
Ammonia as N	1,200
Nitrate	550
Sulfate	1,700
Sulfite	150
Oil & grease	160
Phenol	30
Potassium	60
Arsenic	0.6
Iron	<0.5
Manganese	<0.02
Boron	10
Vanadium	<0.1
Copper	<0.02
Molybdemum	2
Lithium	2
Zinc	<0.02
Aluminum	0.2
Barium	2
Strontium	4
Lead	<0.02
Nickel	<0.02
Cadmium	<0.02

Note: Total alkalinity, carbonate, and bicarbonate water analyses are mg/l as $CaCO_3$.

TABLE V
SULFUR, CARBON, AND WATER BALANCES

RETORT 6 SULFUR MATERIAL BALANCE

Sulfur in-place = 1,500 tons in raw shale	
Sulfur in-products - oil	50 tons
- water	7 tons
- gas	340 tons
- spent shale (by difference)	1,100 tons

RETORT 6 CARBON MATERIAL BALANCE

Carbon in-place = 45,000 tons in raw shale (58% organic/42% inorganic)	
Start-up fuel - diesel = 70 tons	
- propane = 80 tons	
Carbon in-products - gas (59% from organic C/ 41% from inorganic C)	29,000 tons
- oil	7,200 tons
- water	240 tons
- spent shale (by difference)	8,600 tons

RETORT 6 WATER MATERIAL BALANCE

Water in - steam	35,000 tons
- ground water	2,800 tons
Water in-place (before rubbling blast)	5,100 tons
Water generated - diesel combustion	90 tons
- propane combustion	160 tons
- oil combustion	6,400 tons
Water out - water vapor	60,000 tons
- liquid water	6,500 tons

Discrepancy = 17,000 tons

TABLE VI
ENTHALPY BALANCE

RETORT 6 ENTHALPY (HEAT) BALANCE SUMMARY

HEAT IN

	BTU	%
Air	$9{,}100 \times 10^6$	2
Steam	$84{,}000 \times 10^6$	17.5
Water (ground water)	130×10^6	0.03
Carbon combustion	$180{,}000 \times 10^6$	37.5
Oil and oil products combustion	$200{,}000 \times 10^6$	42
Start-up fuel combustion	$4{,}400 \times 10^6$	1
	$480{,}000 \times 10^6$	100

HEAT OUT

Dry offgas	$16{,}000 \times 10^6$	3
Water vapor	$140{,}000 \times 10^6$	29
Liquid water	$1{,}500 \times 10^6$	0.3
Oil aerosol and vapor	230×10^6	0.05
Shale oil	880×10^6	0.2
Carbonate decomposition	$140{,}000 \times 10^6$	29
Heat losses to rubble, surrounding rock, and other chemical reactions	$180{,}000 \times 10^6$	38
	$480{,}000 \times 10^6$	100

Note: liquid enthalpies referenced to 32°F; gas enthalpies referenced to 0°F.

TABLE VII
ENERGY BALANCE

RETORT 6 ENERGY BALANCE SUMMARY

Energy in-place = 800×10^9 BTU

Usable energy out - oil aerosol and vapor		37×10^9 BTU
shale oil		260×10^9 BTU
offgas		240×10^9 BTU
TOTAL		540×10^9 BTU

$$\% \text{ of in-place energy recovered} = \frac{540 \times 10^9 \text{ BTU}}{800 \times 10^9 \text{ BTU}} \times 100 = 68\%$$

Energy required for processing retort - start-up fuel		8×10^9 BTU
steam generation		120×10^9 BTU
electricity		56×10^9 BTU
TOTAL		180×10^9 BTU

$$\text{Operating energy efficiency} = \frac{(540 - 180) \times 10^9 \text{ BTU}}{800 \times 10^9 \text{ BTU}} \times 100 = 45\%$$

Energy required for constructing retort - explosives		0.9×10^9 BTU
mining & construction*		3.9×10^9 BTU
drilling*		2.1×10^9 BTU
retort equipment*		1.5×10^9 BTU
mine equipment*		3.5×10^9 BTU
TOTAL		12.0×10^9 BTU

$$\text{Overall energy efficiency} = \frac{(540 - 180 - 12) \times 10^9 \text{ BTU}}{800 \times 10^9 \text{ BTU}} \times 100 = 44\%$$

*Note: Energy required for mining, construction, drilling and equipment based on data published by Cha and Garrett, "Energy Efficiency of the Garrett In Situ Oil Shale Process," 8th CSM Oil Shale Symposium, April 1975.

in-place. Commercial retorts are expected to have an overall energy efficiency at least 10 per cent higher than that of R6 because of differences in oil shale grade and oil yield and because a commercial operation will use offgas to generate steam for producing electricity and to direct turbine drives on offgas blowers. Some reduction in the fuel needed for retorting steam generation also is expected.

Detailed below is the Retort 6 oil inventory in gross barrels as of August 28, 1979. Note that the total oil produced by Retort 6 is 1,696 bbls greater than reported in the Phase I Final Report. The number in the report, 54,000 bbls, was an estimate because a small amount of oil was still being released by the retort, an accounting of oil in the tanks and lines had not been completed, and vapor/-aerosol figures had not been verified. The estimate figure was also rounded.

Also note that the shipped gross barrels, 40,093, converts to the net barrels shipped of 38,677 for which the DOE was billed.

	Gross barrels
Shipped	40,093
Used in steam plant	3,288
Oil mist lost	7,529
Samples taken	690
Estimated loss from spills*	80
Estimated in sludge tank	1,200
Oil on site	2,816
TOTAL PRODUCED	55,696

* Handled by procedures defined in the Spill Prevention, Control and Countermeasure Plan, OOSI (July 1978) for Logan Wash.

D. PROPOSED RETORTS 7 AND 8 SAMPLING PROGRAM

OOSI, Sandia Laboratories, and LETC have worked closely since August 1980 to develop a comprehensive sampling program for R7 and 8. At a meeting on February 20, 1981, OOSI, LETC and the Oil Shale

Task Force (OSTF) discussed R7 and 8 sampling and developed a schedule to draft and finalize a Task Force sampling and research plan by September 1, 1981. The first draft of the OSTF plan went to DOE-HQ, LETC, and OOSI on May 10. The remaining schedule of dates and objectives is:

- June 15 . . . . . Return review comments to OSTF
- June 25 . . . . . OSTF meeting
- July 10 . . . . . Issue second draft
- Aug. 1 . . . . . Return review comments
- Aug. 10 . . . . . Final review at OSTF meeting in conjunction with Environmental Symposium at Vail, Colo.
- Sept. 1 . . . . . Final plan

The R7, 8 and 8X thermocouple and sample tap plan started prior to August 1980. See the Quarterly Progress Report for the period December 1980 through February 1981 for details. The plan calls for installation of over 700 thermocouples and 150 sample taps in 150 cased holes in the rubble over a three to four month period starting in June 1981 (See Figures 13 through 16). The TC installation procedure has four steps: 1) grout drill stem in place, 2) log (survey) holes, 3) install TC's and sample tap; and 4) grout TC's in place. The final plans depend upon drilling circumstances encountered and sampling logistics at the time of instrument installation. Table VIII shows the total number of TC's and holes planned just prior to the beginning of TC installation in June.

E. PHASE I AND PHASE II ANALYSES

To fulfill, to the letter, the content of the Agreement Scope of Work which calls for an analysis section in each quarterly and annual report, this section on the Phase I and Phase II Analyses is being supplied. Listed here are the analysis topics and where the entire analysis for each topic can be found.

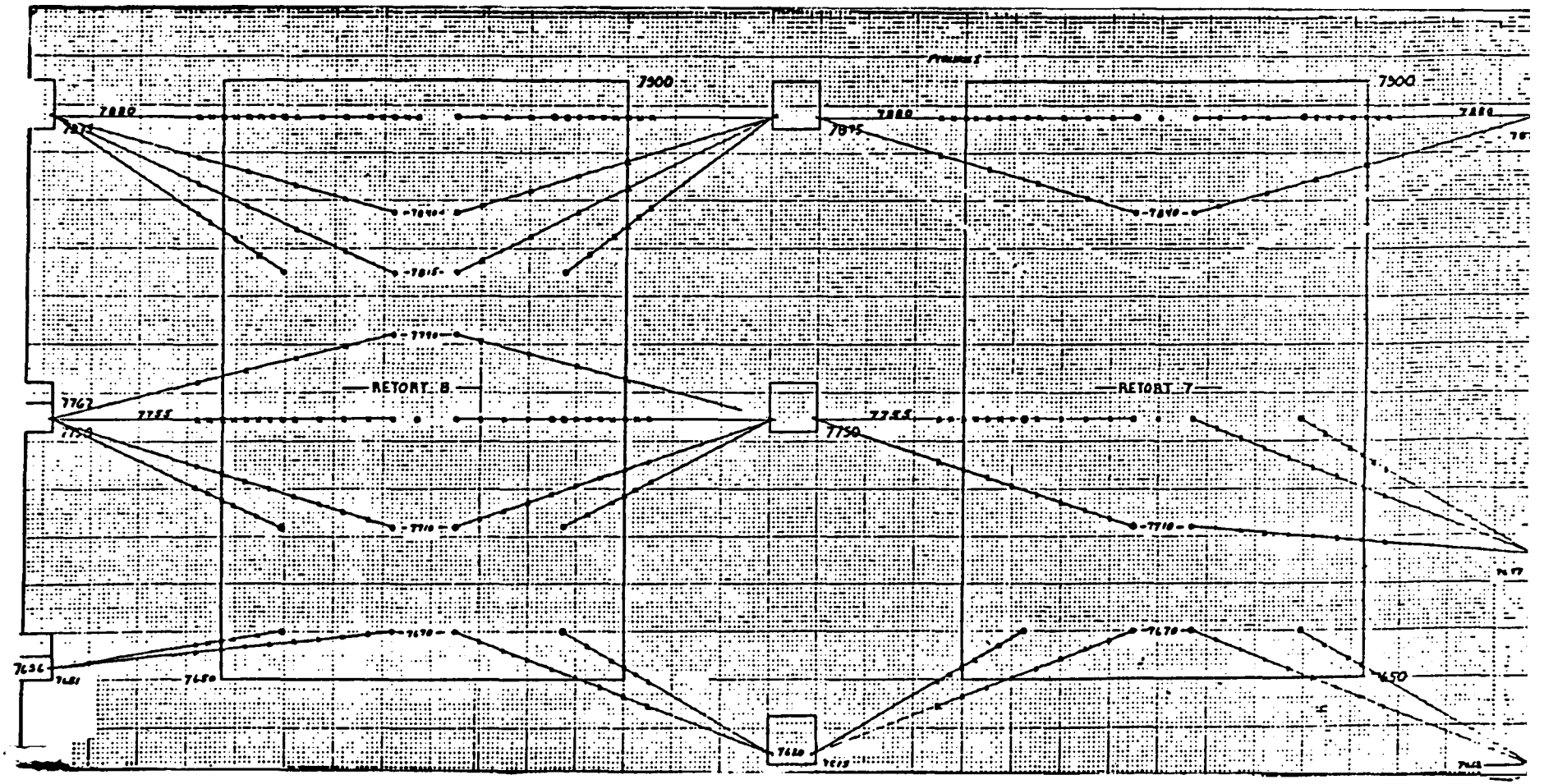


Figure 13. Retort 7 and 8 thermocouple and gas sample drill hole pattern, vertical section

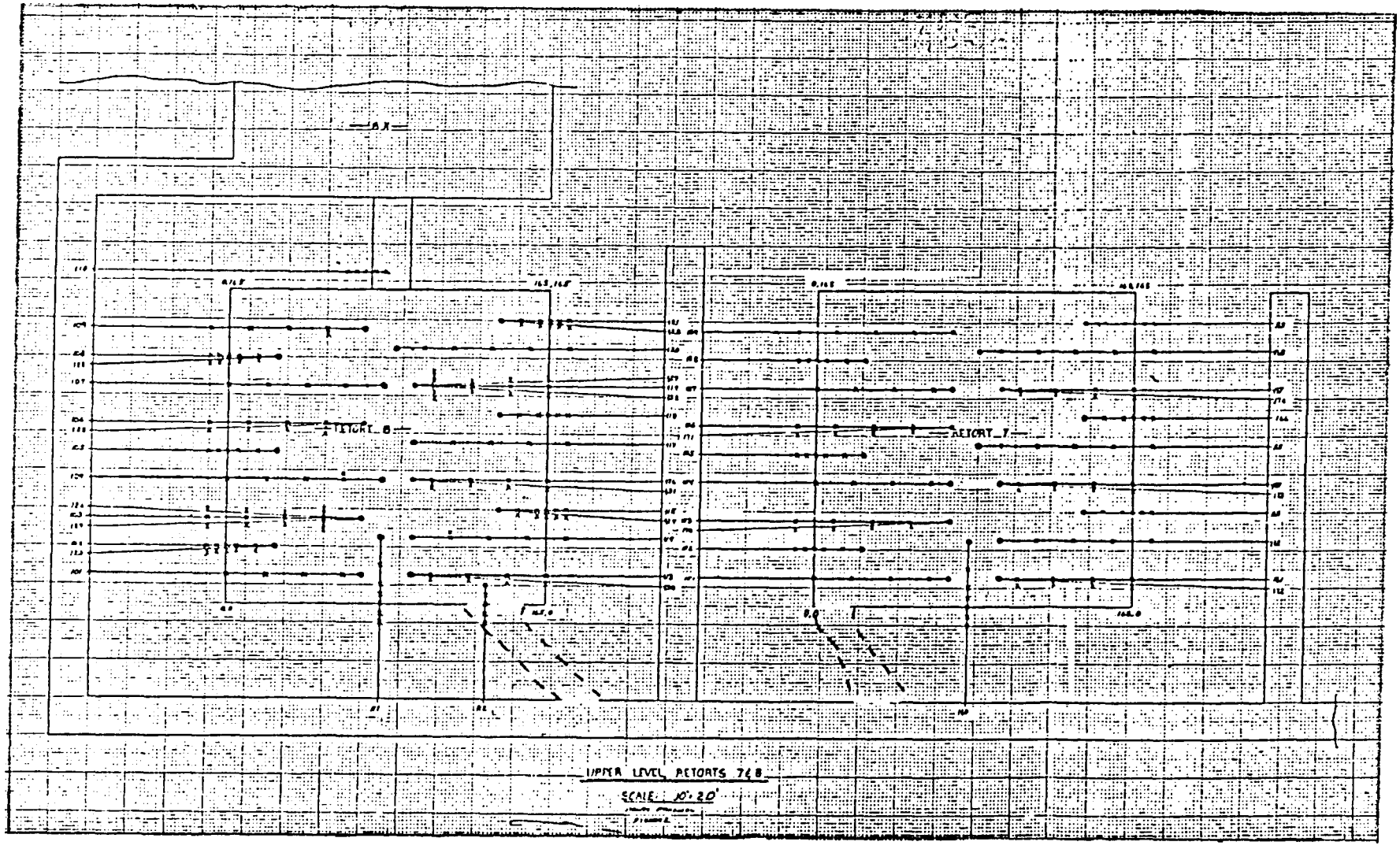


Figure 14. Retorts 7 and 8 Upper Level sample tap and thermocouple grid patterns, plan view.

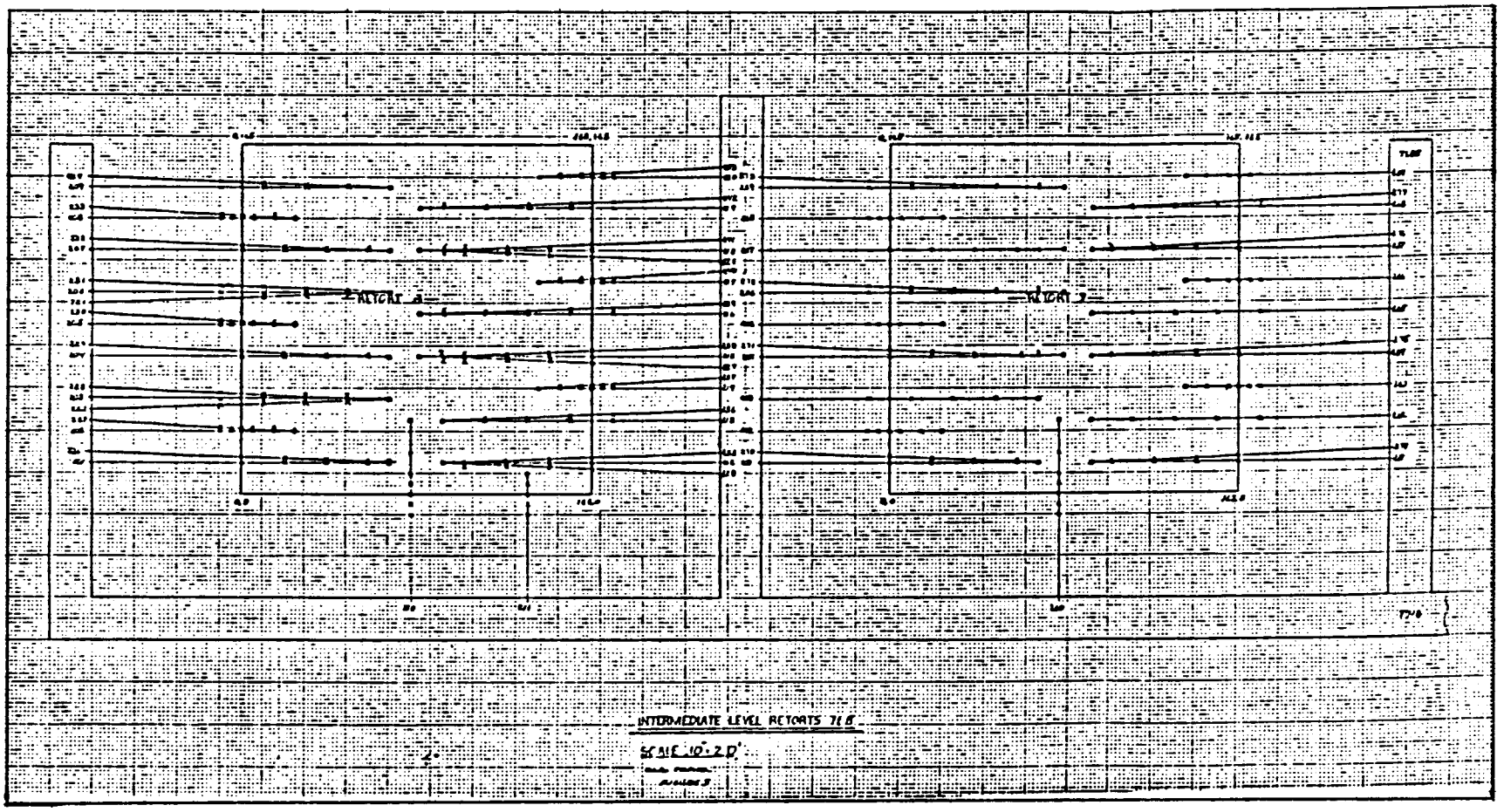


Figure 15. Retorts 7 and 8 Intermediate Level sample tap and thermocouple grid patterns, plan view.

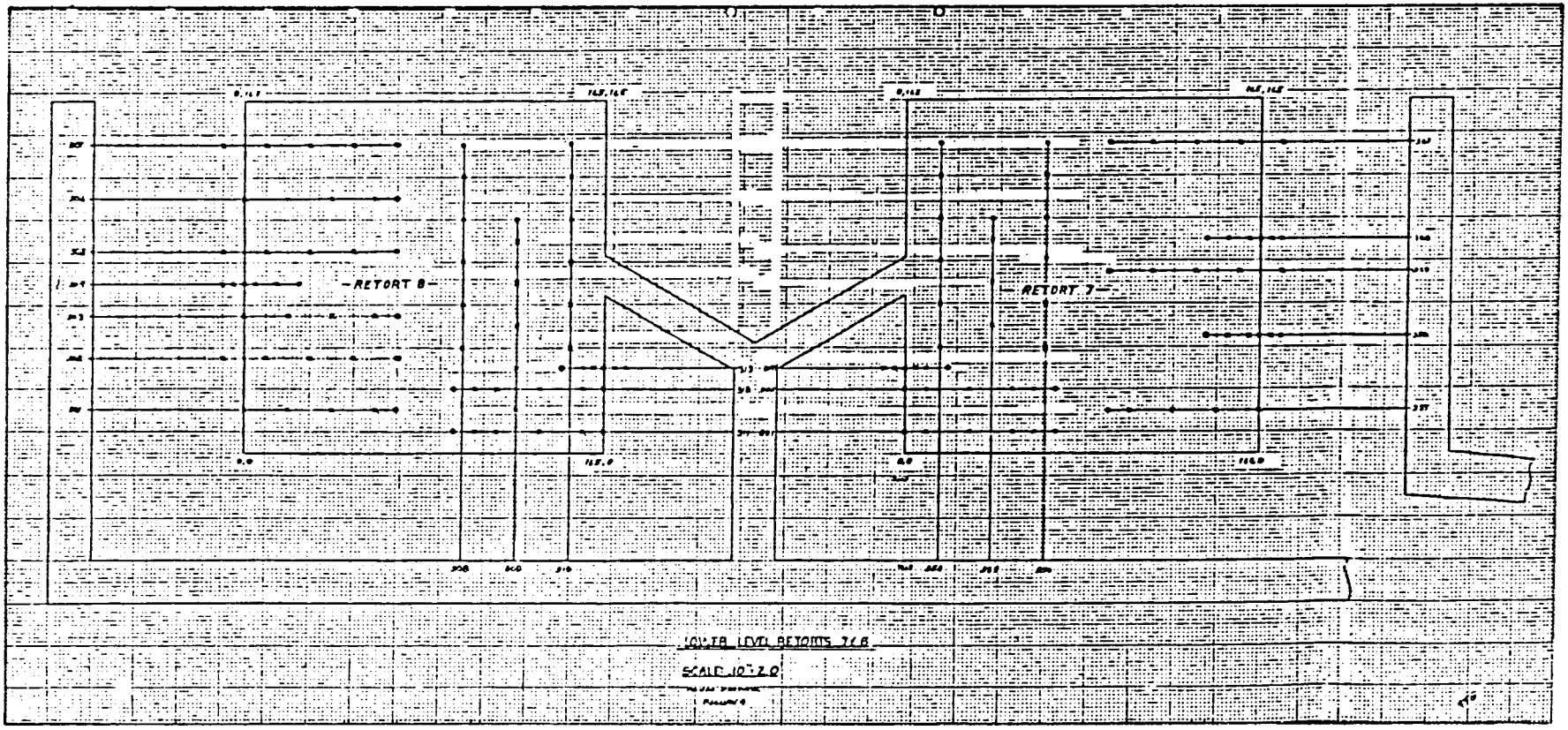


Figure 16. Retorts 7 and 8 Lower Level sample tap and thermocouple grid patterns, plan view.

TABLE VIII
RETORTS 7 & 8, Room 8X - OOSI & SANDIA THERMOCOUPLES

INSTRUMENT HOLE END ELEVATION	DRILLING LOCATION	RETORT 7				RETORT 8				ROOM 8X				TOTALS			
			THERMOCOUPLES				THERMOCOUPLES				THERMOCOUPLES				THERMOCOUPLES		
		HOLES	RUBBLE	PILLAR	PROCESS	HOLES	RUBBLE	PILLAR	PROCESS	HOLES	ROBBLE	PILLAR	PROCESS	HOLES	RUBBLE	PILLAR	PROCESS
7894'-8615'		4	--	76	--	4	--	76	--	--	--	--	--	8	--	152	--
RUBBLE SURFACE/VOID		--	20	--	--	--	20	--	--					--	40	--	--
7870'	(UL)	19	85	20	2	20	91	22	2	1	--	5	1	40	176	47	5
7840'	(UL)	5	23	2	--	5	27	2	--					10	50	4	--
7815'	(UL)	--	--	--	--	6	27	9	--					6	27	9	--
7790'	(IL)	--	--	--	--	5	25	2	--					5	25	2	--
7760'	(IL)	1		7	2	1	--	7	2					2	--	14	4
7755'	(IL)	19	87	20	--	20	90	22	--					39	177	42	--
7710'	(IL)	8	40	3	--	18	82	18	--					26	122	21	--
7670'	(LL)	11	55	8	--	13	63	9	--					24	118	17	--
7650'	(LL)	--	--	--	--	--	--	--	1					0	--	--	1
7615'	(PL)	1	--	3	6	1	--	3	6					2	--	6	12
7607'-7648'	(PL)	2	--	8	--	2	--	8	--	--	--	--	--	4	--	16	--
TOTALS		70	310	147	10	95	425	178	11	1	0	5	1	166	735	330	22

GPG/BAR
5/7/81

The reports not covered here which already have analytical sections are: the Summary Report for November 1, 1976, through October 31, 1977, and the Quarterly Reports from June 1, 1980, through February 28, 1981. In each of the reports the environmental analyses are in the Environmental Support sections.

Topic	Report	Page
Retort 5	Quarterly, 11/01/77-01/31/78	1
R5 processing parameters	Quarterly, 11/01/77-01/31/78	App. A
Histogram for oil-in-place	Quarterly, 11/01/77-01/31/78	App. C
R6 flow/tracer tests	Quarterly, 05/01/78-07/31/78	1, App. A
Retort 5	2nd Annual,11/01/77-10/31/78	2
R6 flow/tracer tests	2nd Annual,11/01/77-10/31/78	7, App. C
R6 retorting	2nd Annual,11/01/77-10/31/78	9
R6 offgas, oil and water analyses	2nd Annual,11/01/77-10/31/78	17
R6 rubbling	2nd Annual,11/01/77-10/31/78	4, App. A
Marketing Studies	2nd Annual,11/01/77-10/31/78	50,App.N&O
R6 retorting	Quarterly, 11/01/78-01/31/79	1, App. A
R6 offgas, oil and water analyses	Quarterly, 11/01/78-01/31/79	4
Marketing Studies	Quarterly, 11/01/78-01/31/79	22, App. D
Summary & Conclusions	Final, 11/01/76-04/30/79	1
R5&6 flow/tracer tests	Final, 11/01/76-04/30/79	25, App. B
R5&6 retort performances	Final, 11/01/76-04/30/79	27,App.C,D
R5&6 offgas, oil and water analyses	Final, 11/01/76-04/30/79	42
Offgas treatment	Final, 11/01/76-04/30/79	48
Mine stability	Final, 11/01/76-04/30/79	50

The raw data for tracer tests prior to R6 retorting and during the retorting were supplied as indicated in the list. Very little OOSI interpretive information is supplied in these public progress reports because this information is only supplied with "limited rights" under the Cooperative Agreement.

During the first year of Phase II, the major efforts were mining, construction, and instrumentation planning. Therefore there were no analyses during that period except for ongoing environmental work. The reports following that first year include analyses sections.

1. Retorts 5 and 6 Summary

For more than eight years Occidental Oil Shale, Inc. has been engaged in MIS process technology development. The Occidental philosophy in developing this process for producing oil from shale is to maximize the recovery of inplace oil while minimizing costs and the environmental impact.

OOSI prepared and processed its fifth and sixth retorts under a cooperative program with the Department of Energy. The DOE/Occidental Cooperative Agreement is a two-phase agreement consisting of engineering development of two specific retort designs for the Occidental MIS process as the first phase and a technical feasibility demonstration as the second phase. More specifically, the major objectives of Phase I were:

- Construct and process large scale retorts (Retorts 5 and 6) formed by blasting to both vertical and horizontal free faces.

- Develop geologic and mine stability data for use in Phase II.

- Prepare definitive engineering designs of facilities for a technical and commercial feasibility demonstration utilizing one of the designs tested earlier in this phase.

- Project a commercial cost estimate from the definitive engineering design.

- Conduct an environmental research program to collect and evaluate data and to report environmental conditions and any changes in conditions during the work activities identified in the Agreement.

The intent of Phase I was to develop the information needed for the construction of the technical feasibility demonstration plant planned for Phase II.

In Retort 5, the mined void volume was removed from the retort zone in the form of a vertical slice along the center of the room extending from the top of the rubble pile to be formed, to the production level. This system is known as a vertical free face retort system (VFFR). The second system, Retort 6, consisted of mining out three horizontal levels in a fashion similar to room and pillar mining and then blasting the oil shale above and below the mined out sections to the horizontal rooms. This system is the horizontal free face retort system (HFFR).

Based upon the results of Retorts 5 and 6, the design using horizontal rooms and a new technology of blasting to a horizontal free face, developed from the Occidental sponsored Rock Fragmentation Program, was selected over the vertical slot because:

- Field results have confirmed that the HFFR system is much more amenable to the achievement of a rubble pile with uniform flow characteristics than is the VFFR system.

- The more uniform void volume distribution with the HFFR design results in improved retort operability and oil yield.

There are advantages and disadvantages inherent in both retort designs. Of concern are the rubble particle size distribution in the retort, sill pillar stability, and retort formation costs. Uniform particle size and void distributions through the retort from top to bottom during processing are critical to the successful processing of the MIS retorts. Here the HFFR system has the greatest advantage over the VFFR system. The rock may move up and down to a horizontal free face without creating a significant disparity in permeability in the horizontal cross section. If there is to be a non-uniform permeability in the HFFR system, it is most likely to occur in the vertical cross section; i.e. the permeability might be greater in the area near the free face and less farther away from the free face. While this would not affect the air flow distribution through the retort pattern, there could be a significant effect on incremental pressure drop. The presence of a pillar(s) in the HFFR system presents a similar problem to that of the VFFR in that it first necessitates the blasting of the pillar prior to the main rubbling blast. The objective is to remove the pillar prior to initiating main rubbling by sequence blasting and thereby distribute the rock from the pillar across the retort cross section.

In the vertical void system the greatest potential for non-uniform permeability is in the horizontal direction. If this system is to be effectively developed, this inherent disadvantage will have to be overcome through optimization of the blasting pattern.

Both Retorts 5 and 6 utilized a sill pillar concept. This means that the mining level at which the air entered the top of the retort was vertically separated from the rubble pile by a distance of 40 to 50 feet of solid rock. The sill pillar provides access to the retort for distributing and controlling the inlet gas and seals the hydrocarbon containing retort gases

from the mine atmosphere. In both systems, the blast holes that were charged with explosives to rubble the retort were loaded with explosives to the base of the desired sill pillar. When shooting to a vertically mined void, the rock displaces horizontally away from the blast hole and there is a minimum potential for damage of the sill pillar. With the HFFR system, the free face is a considerable distance below the top to the loaded blast holes. The rock must expand in the downward direction. However, as there is also a free face vertically displaced above the sill pillar (air level), there is some potential for the blast to extend in the upward vertical direction, which could damage the sill pillar.

The manner of mining the void volume is significantly different in the two systems and this is where the VFFR system may have its greatest advantage. The preparation of the vertical slot is accomplished from the air level above the sill pillar with muck removal handled from the lower product level. Mine productivity for slot formation is relatively high and consequently more economical. With the HFFR system, the rock must be mined as a room and pillar operation on several levels, and relative to the VFFR system, the cost of void mining is higher.

Occidental funded, separately from the Cooperative Agreement, an extensive rock fragmentation program. This program was used to develop the blasting pattern for Retort 6 as well as data on particle size and particle size distribution for that retort.

Based on experience with six MIS retorts Occidental Oil Shale, Inc. recommended that DOE and OOSI:

- proceed with the Phase II technical feasibility demonstration at the D.A. Shale site (Logan Wash) with a two retort cluster of horizontal free face design;

- further study rock stability and rubbling blast effects; and
- further simplify HFFR designs.

Major conclusions derived from the Phase I work are:

- The bottom design of a retort can have a significant effect on oil recovery, oil entrainment in the offgas, overall pressure drop, and offgas temperature.
- A single vertical slot based on the Retort 5 design does not provide adequate radial distribution of void and particle size.
- Secondary combustion can be used for some degree of flow control when small differences in permeability exist.
- Shale oil can be used to ignite a retort with an energy requirement close to that predicted.
- Offgas data cannot be solely depended upon for use in predicting retort behavior.
- HFFR design can provide more uniform vertical flow and better particle size.
- Further burner development is needed.
- Retort 6 was very well rubbled (based on extensive tracer work).
- The in situ technology was confirmed in a full scale retort.
- No indication was found of any plasticity problems in Retort 6 although retorting passed through the mahogany zone.
- Less seismic damage and a better powder distribution can be obtained in HFFR rubbling.

2. Description

Retorts 5 and 6 were the second and third large-sized MIS retorts processed at OOSI's D. A. Shale site (Logan Wash). Retort 6 differed from the previous two large-sized retorts (Retorts 4 and 5) because the mined out void volume consisted

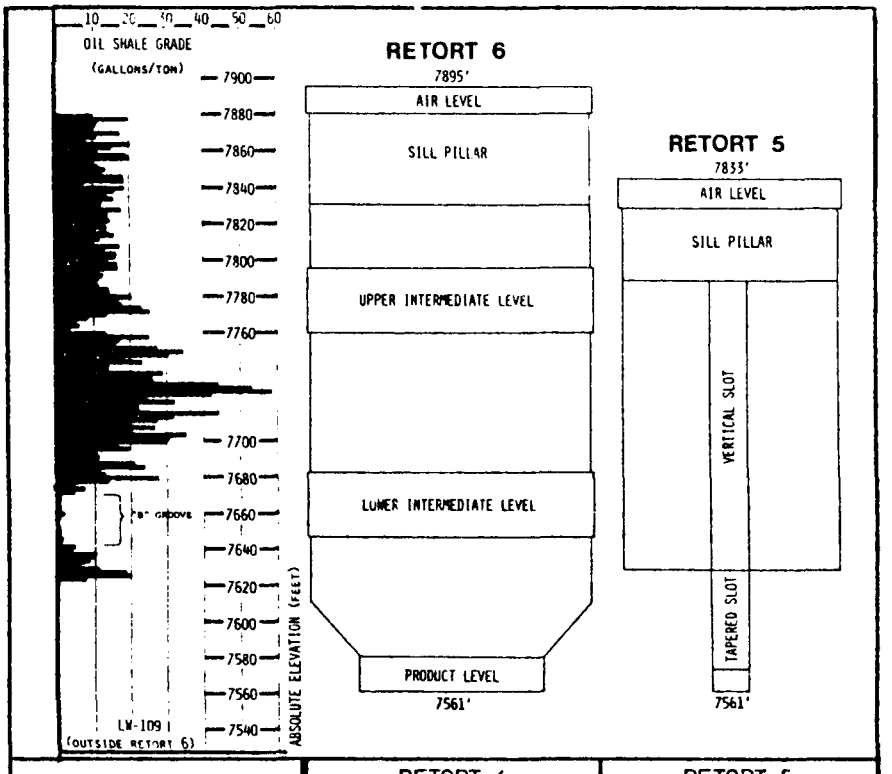
of horizontal rooms separated by solid zones of oil shale rather than the vertical slots for the free face and void volumes used in Retorts 4 and 5. Retort 6 was essentially a scaled-up version of OOSI's Retort 3E which was a small scale (32' x 32' x 113'), multiple level, horizontal free face experimental retort.

The overall dimensions, other retort specifications, ignition and processing summary and retort locations relative to the oil shale histogram are shown in Figure 17 for both retorts. The indicated retort heights are measured from the top of the sill pillars to the bottom of the bulkhead and include the sill pillars which were 40-ft thick for Retort 5 and approximately 50-ft thick for Retort 6. Two support pillars, extending almost the full length of the Air Level rooms for each retort were left intact to provide support for the roof. Retort 6 also had support pillars in the Intermediate and Product Level rooms which were subsequently rubbled.

3. Rubbling

Retort 5 was rubbled by blasting into the single vertical slot which ran from the bottom to the sill pillar of the retort and across the retort. The slot had been tapered into a trapezoidal shape at the bottom of the retort to facilitate mucking rock from a single draw point during mining.

The rubbling holes were loaded with 170,150 pounds of explosive. The uppermost 40 feet of the holes were not loaded but filled with a stemming material, thus leaving a 40-ft thick sill pillar under the floor of the Air Level. Each was multi-primed, to provide a high degree of reliability, and equipped with a blast detector, to give a positive indication of explosive detonation.



	RETORT 6	RETORT 5
SPECIFICATIONS		
Dimensions	164'x 164'x 334'	118'x 118'x 272'
Rock Rubblized (Tons)	362,000	140,450
Average Fischer Assay (GPT)	15.6	15.7
Average Void Volume (%)	23.1	17.3
Void Arrangement	3 Horizontal Rooms	1 Vertical Slot
Oil-in-Place (Barrels)	133,300	52,500
Quantity of Explosives (lbs.)	386,000	170,150
IGNITION		
Start-up Date	August 28, 1978	April 18, 1977
Start-up Fuel	Diesel & LPG	Shale Oil & Diesel
PROCESSING		
Retorting Gas	Air & Steam	Air & Steam
Average Stack Gas Flow Rate (SCFM)	21,500	7,000
Average Advance Rate (ft/day)	.83	1.12
Oil Produced Barrels - reclaimed, aerosol, pumped	54,000*	11,047
Actual Yield (% of oil-in-place)	40	21
Oil Recovered (Barrels)	45,000+	4,373
Date of Permanent Shutdown	July 17, 1979	November 8, 1977

* Estimated

\+ Estimated - final accounting incomplete as of August 15, 1979

Figure 17. Retorts 5 and 6 comparison summary.

The rubbling blast was set off at 8:00 a.m., Thursday, December 16, 1976 following a pre-determined blasting sequence. No primadet lines remained in any of the blast holes thus indicating positive activation of each hole.

The rubbling of Retort 6 was more complicated than Retort 5 because the retort was larger, it had more blast holes, and the blasting sequence also involved first shooting the support pillars in the Intermediate and Product Level rooms. The rubbling holes were loaded with 386,000 pounds of explosive; more than twice that used in Retort 5, although the powder factor was about the same. The uppermost 50 feet of the holes through the sill pillar were not loaded with explosive, but were stemmed thus leaving the sill pillar averaging 45 feet thick. Each hole was multi-primed for reliability.

The rubbling blast was set off at 8:00 a.m., Saturday, March 25, 1978, following a pre-determined blasting sequence. Retort 6 was rubbled by blasting into the three horizontal rooms located at the Upper Intermediate, Lower Intermediate and Product Levels.

The blast design utilized was to have produced a "bulked-full" retort. However, although subsequent tracer testing confirmed that the shale had been effectively and uniformly rubbled, the retort did not bulk full. The rubble pile within the retort had a domed shape and the gap between the top of the rubble pile and the bottom of the sill pillar ranged from approximately eight feet at the center of the retort to approximately 35 feet in the corners. The sill pillar itself, which had been designed to have a thickness after rubbling of 40 feet, had an average thickness of 45 feet with the thickness at the center being approximately 40 feet and at the extremities, approximately 50 feet. The design void volume was 23% of the total void volume.

For both retorts, post-blast surveys were made and photographs taken of the same areas surveyed prior to the rubbling blasts. Additionally the data from the various monitors were analyzed.

No significant damage was found around either retort. The mine areas around Retort 5 sustained more damage during the rubbling blast than they did for Retort 6. In the lower level, at the Retort 5 bulkhead, two cracks were noted and repaired in the area where the bulkhead was fastened to the walls. Also at the intersection of the L-700-N and L-1 drifts, a section of wire and roof bolts had come down. Minor rock spalling appeared in other areas. At the surface, the stack withstood the blast with no damage of any kind. Within the mine, the instrumentation at the Air Level indicated the largest amount of ground movement in the proximity of the retort, with lesser amounts at distances farther from the retort.

During the blast of Retort 6, a small amount of rubble was blown into the drifts at the two intermediate levels. This rubble was mucked out to points inside the drifts (toward the retort) where the bulkheads were to be installed. A visual inspection of the rubble during the mucking operation, at the Product Level, and under the sill pillar, indicated that the particle size was within the desired range. The seismic measurements supported the survey findings that minimal damage was incurred.

Inspection under the sill pillar, also showed that Retort 6 had not bulked full. The sill pillar remained stable for five months after the blast without support over the 164' x 164' cross section without any major sloughing.

4. Flow/Tracer Tests

Retorts 5 and 6 both underwent diagnostic testing prior to ignition. The flow and tracer tests were conducted to determine the pre-ignition pressure drop, the total and active

voids, and the gas flow distributions in various sections of the rubble pile in each retort.

Krypton-85 tracer tests were run to measure axial gas dispersion and to characterize the degree of rock fragmentation. The test procedure was modified for Retort 6 to not only use single injection points with multiple detection points but also to use manifold injection points with multiple detection points for improved gas dispersion.

The air leakage rate at various retort pressures and changes in static pressure at various times were measured to determine the total void. The active void was measured by injecting carbon monoxide into the retorts which were operated at total recycle air flow. The data from these tests on Retorts 5 and 6 appear in the First and Second Annual Progress reports, and the Phase I Final report, along with more detailed discussions on test procedures and injection/detection points.

Several conclusions were drawn from these tracer tests. For Retort 5:

- The retort was not uniformly rubbled and preferential flow occurred in different areas of the retort.
- In some sections of Retort 5, there was high gas flow resistance between some of the holes through the sill pillar and the next row of adjacent holes, indicating non-uniform breakage in the radial direction.
- Some of the void spaces near the outer edge of the retort were inactive.

The retorting program planned for Retort 5 was modified because of the non-uniform radial rock fragmentation. An attempt was

made to keep oxygen from those areas which indicated preferential flow in the tracer tests.

After Retort 5 ignition, a portion of the Krypton-85 tracer tests was repeated at intervals during the processing of the retort to determine if the flow pattern and void volume distribution had changed. The indications were that the void distribution had improved continuously after ignition and that the non-uniform gas flow problems were not so pronounced in September as they had been in March, before ignition.

For Retort 6, the conclusions were:

- Retort 6 had considerably more uniform gas flow distribution than Retort 5.
- The areas above and near the Intermediate Level bulkheads had higher permeability since a significant amount of rubble was ejected from the retort into the Intermediate Level entrance drifts during rubbling.

Krypton-85 tests were also repeated on Retort 6 during retorting and just prior to shutdown. Tests were run in November 1978, and January and July 1979. The tests showed changes in the flow bed characteristics as well as confirming areas of preferential gas flow. The final tracer test verified that most of the retort volume had been retorted by mid-July.

Also during the Retort 6 operation, a new tracer gas was used to determine: 1) whether Intermediate Level sampling tubes could be used for LPG injection for secondary combustion; and 2) the flow behavior when air was introduced through the Upper Intermediate Level (UIL) bulkhead.

This tracer is a non-toxic, colorless, odorless, tasteless, non-flammable and non-corrosive inert gas. It can be detected at high sensitivity with electro-capture gas chromatography.

Even under the difficult mine environment a sensitivity of down to $5x(10)^{12}$ parts of the gas can be obtained with very satisfactory accuracy.

For the first test, the tracer was injected at a constant rate along with compressed air into sampling tubes at the Upper Intermediate Level. Readings were made at various locations on the UIL as a function of time. The steady-state value was then used to determine the combined leakage rate of the tracer from the sampling tube, formation, and injection system. For the tubes sampled, the combined leakage was only $3x(10)^{-5}$ in the worst case. Since the flammable limit for LPG is 2% LPG it was concluded that there was no danger of explosion from LPG injection at the Upper Intermediate Level.

For the second test, the tracer was injected with compressed air at the UIL bulkhead. Its concentration was then determined as a function of time at various sampling locations at the Lower Intermediate Level. Its mean residence time was then compared with the calculated arrival time based on flow rate. The comparison indicated areas of preferential flow. However, a mass balance of the tracer showed that a major portion of it was decomposed in the retort due to the high temperature at the retorting front. Therefore, the validity of the results were hard to assess.

5. Retort Performances

Because OOSI intrepretations of retort data are protected under the rights in technical data in the Cooperative Agreement, only a few observations and discussions of retort performance are presented.

Retorts 5 and 6 each encountered problems which affected their performance. In Retort 5 the non-uniform distribution of void across the center of the retort resulted in poor performance beginning early in the retorting process. The combustion front

moved rapidly down the front center of the rubble where pre-ignition tracer tests had indicated that the fraction of void volume was higher than the rest of the rubble pile. Efforts throughout its operation concentrated on corrective measures leaving little steady-state normal operating time for evaluation.

Retort 6 performance was good considering the upset conditions experienced during ignition. Since the retort had not bulked full, OOSI considered whether or not to proceed with processing the retort in this condition. OOSI and outside consultants studied whether the sill pillar had adequate mechanical strength to allow it to remain intact during the course of the retorting operation particularly during the two week start-up period without experiencing excessive thermal spalling and failure.

It was concluded that the sill would maintain its structural integrity even if it were to spall to a thickness of 20 to 25 feet. Also no significant spalling should occur within the scheduled 20-day start-up period.

In view of these analyses, the decision was made to proceed with the processing of Retort 6. However, two precautions were taken. To enhance the mechanical strength of the sill pillar, it was rock bolted on a ten foot pattern using bolts ranging in length from 30 to 40 feet. These bolts were inserted in the sill and then grouted in place. In addition, work was initiated on construction of two bulkheads which would allow Retort 6 to be isolated in the event that problems with the sill pillar were encountered.

During ignition, a portion of the Retort 5 sill pillar deteriorated causing an upset in operating conditions. As a result of the upset, measures were also needed midway in the retort operation to correct an imbalance in the retorting front. This too, left little steady state normal operating time for

evaluation. Some performance comments however, can still be made.

Criteria had been established defining commercially acceptable values of active void and mean residence time ratios prior to the rubbling of Retort 5. Retort 6 met these criteria and had a lower pressure drop and better flow characteristics than Retort 5. These results were predicted by comparing tracer test results from Retorts 5 and 6.

OOSI's ability to control input conditions at the top of the rubble pile were very limited during the operation of Retort 6. Since the Air Level was inaccessible after the upset during ignition, engineers were unable to change flows to alter the inlet gas distribution. Performance based on these factors cannot be accurately evaluated.

Water produced versus water consumed in Retort 6 was approximately equal. The water requirements for Retort 6 were less than that of Retort 5 per barrel of oil produced.

Analysis of the Retort 6 offgas curves shows that with all the corrective measures taken, and also during the upset, daily predictions of retort behavior are not possible. The use of the curves has not been developed to the point where the curves can be predictive tools. They give a macroscopic view of the process in showing trends during operation. For example, excluding the upset period on the curves, operation appears orderly and smooth throughout Retort 6 processing even though oil production began declining in February. Figures 18 through 22 show combined Retort 5 and 6 performance for several gases, flow and oil production.

6. Analytical

The analytical data for Retort 5 were presented in the First Annual Progress report and have not been repeated here. For

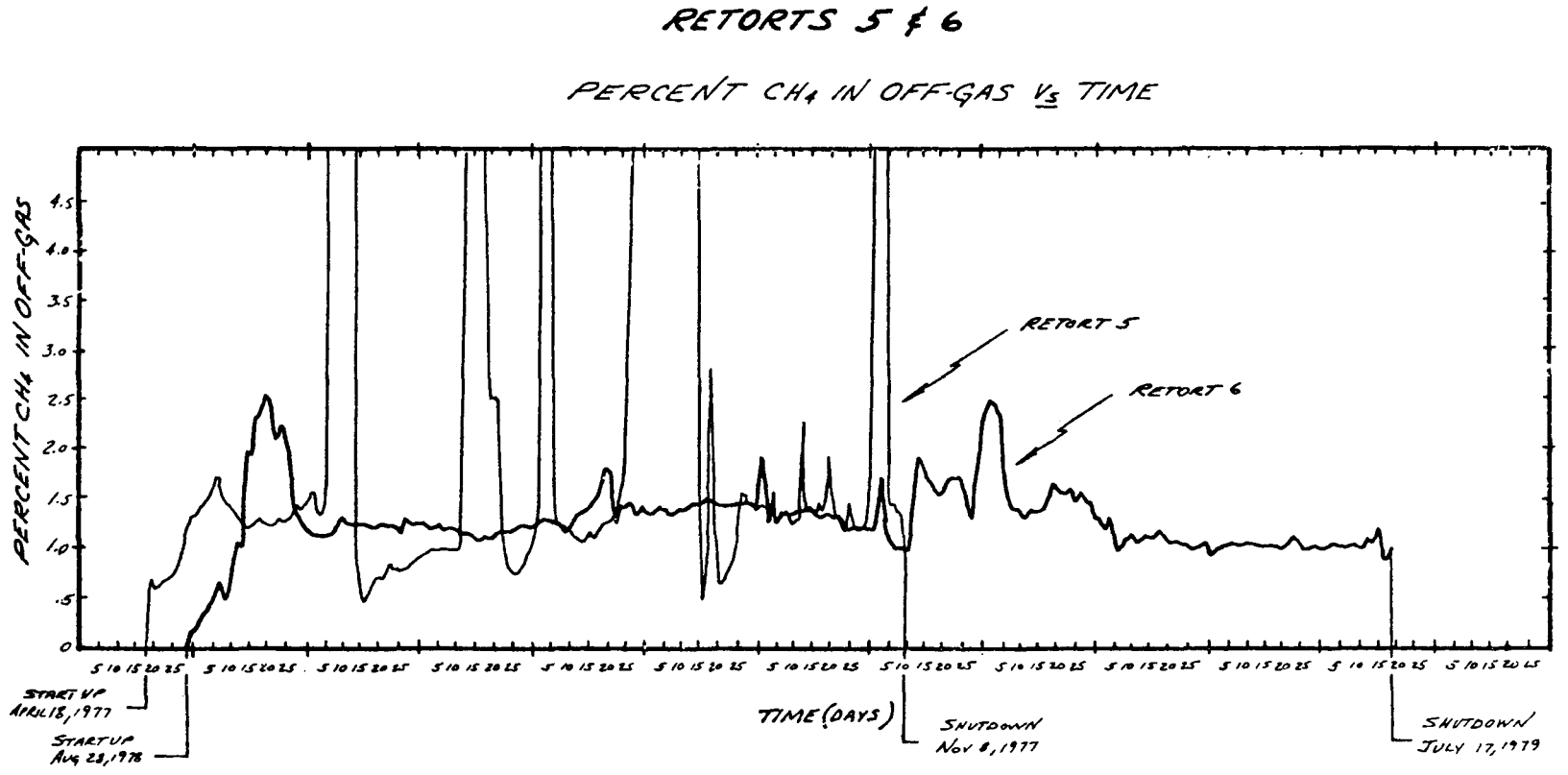


Figure 18. Comparison of the percent of CH_4 in the offgas of Retorts 5 and 6.

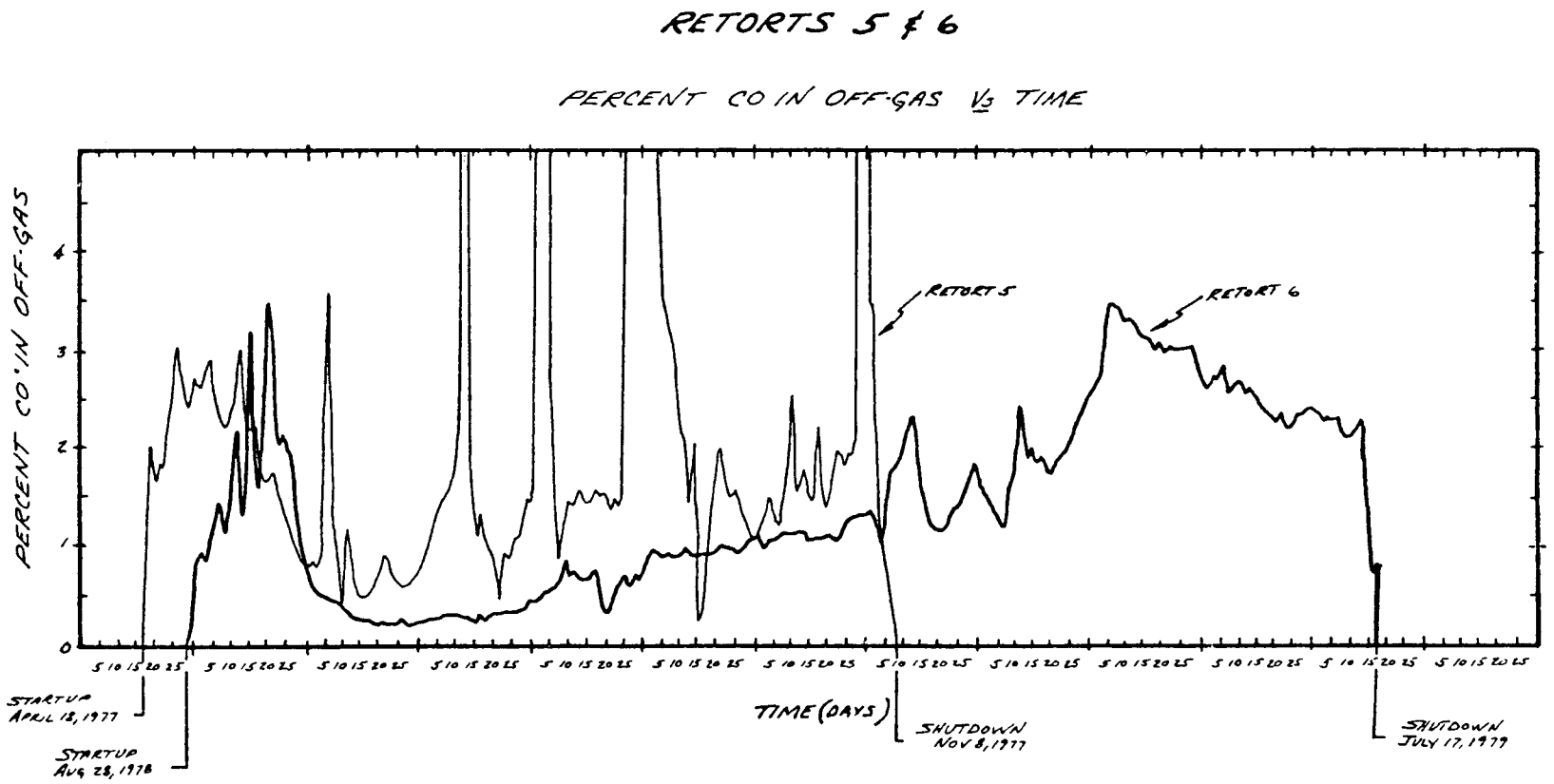


Figure 19. Comparison of the percent of CO in the offgases of Retorts 5 and 6.

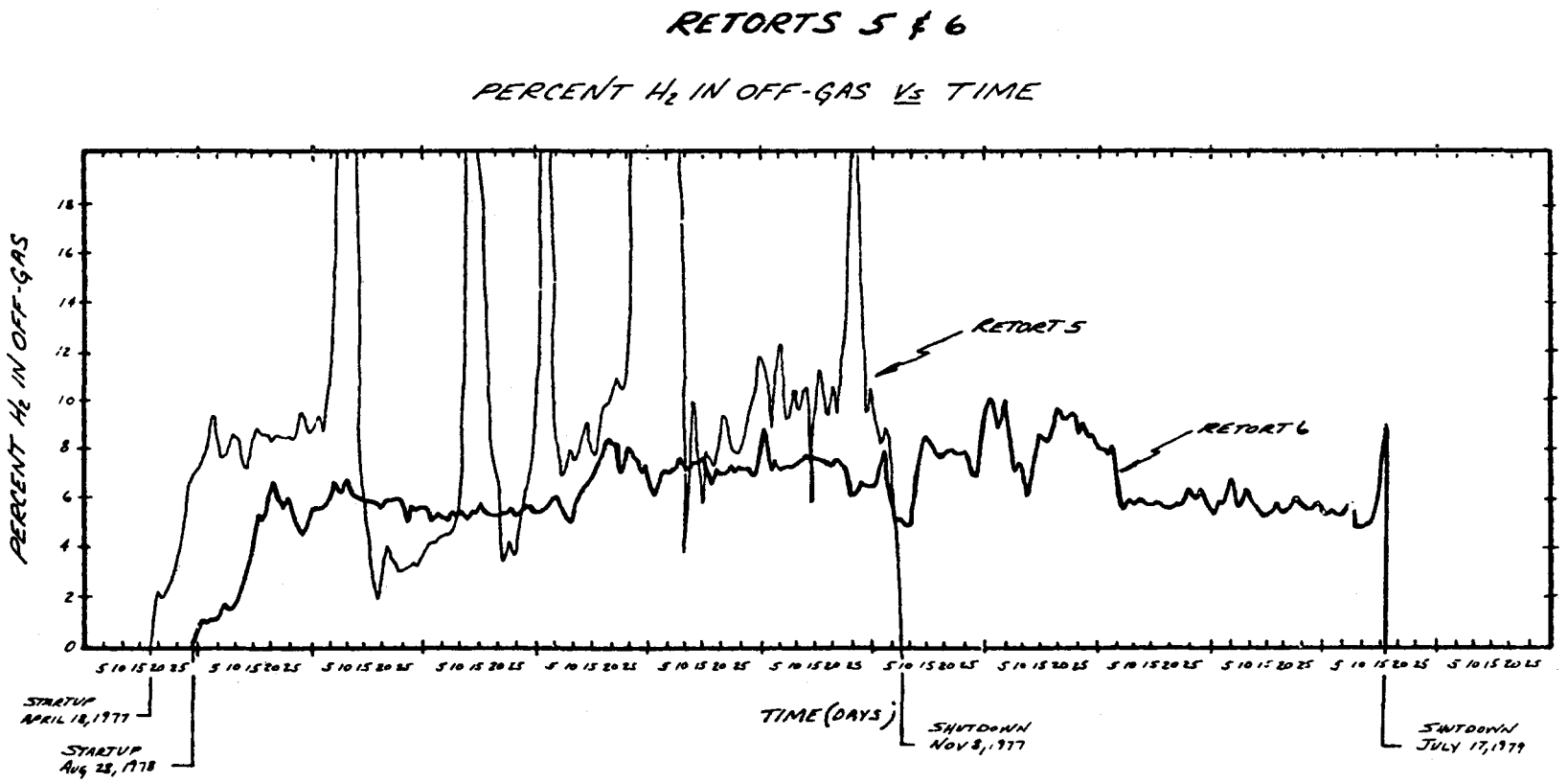


Figure 20. Comparison of the percent of H_2 in the offgases of Retorts 5 and 6.

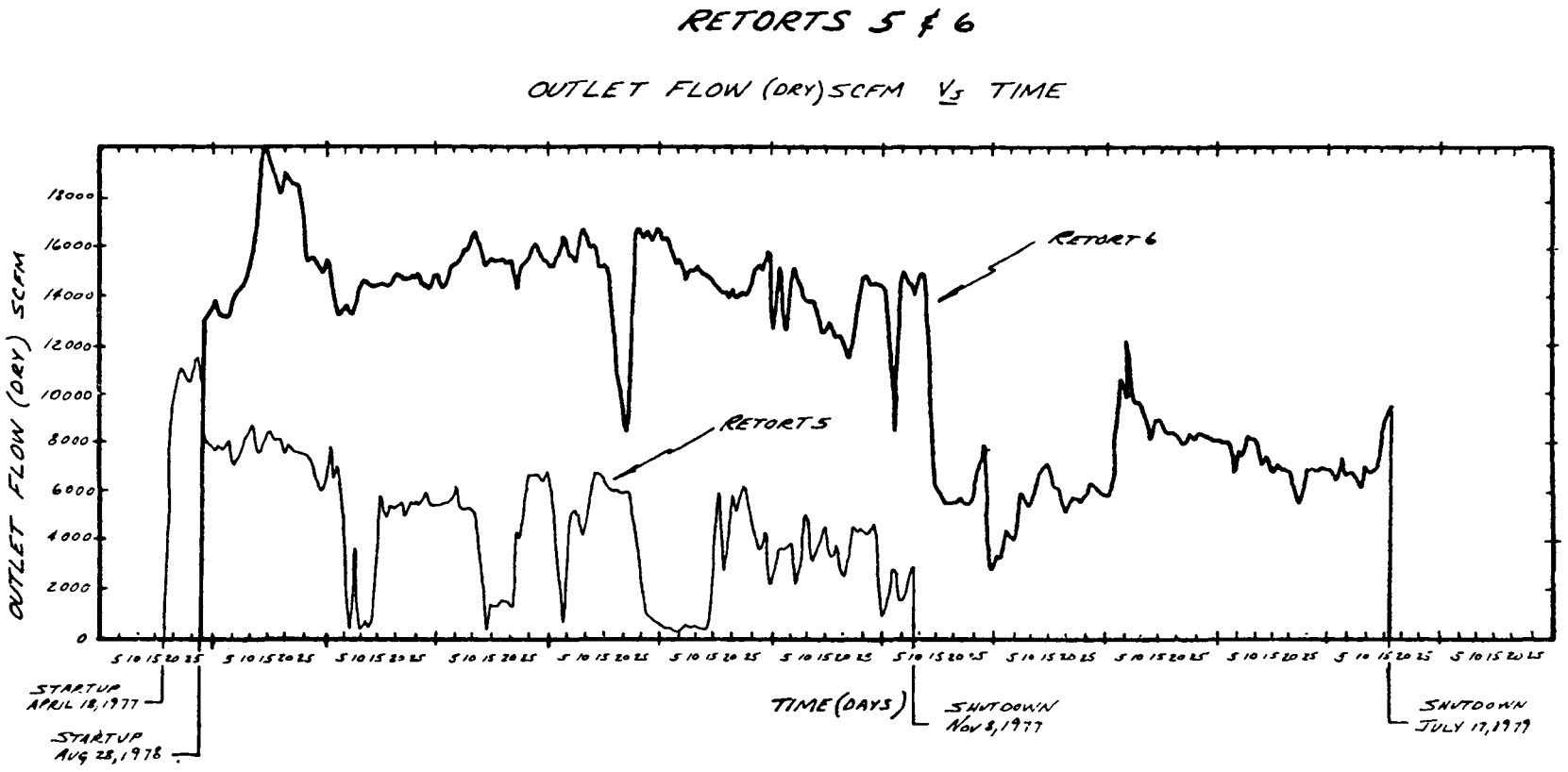


Figure 21. Comparison of the dry outlet flow for Retorts 5 and 6.

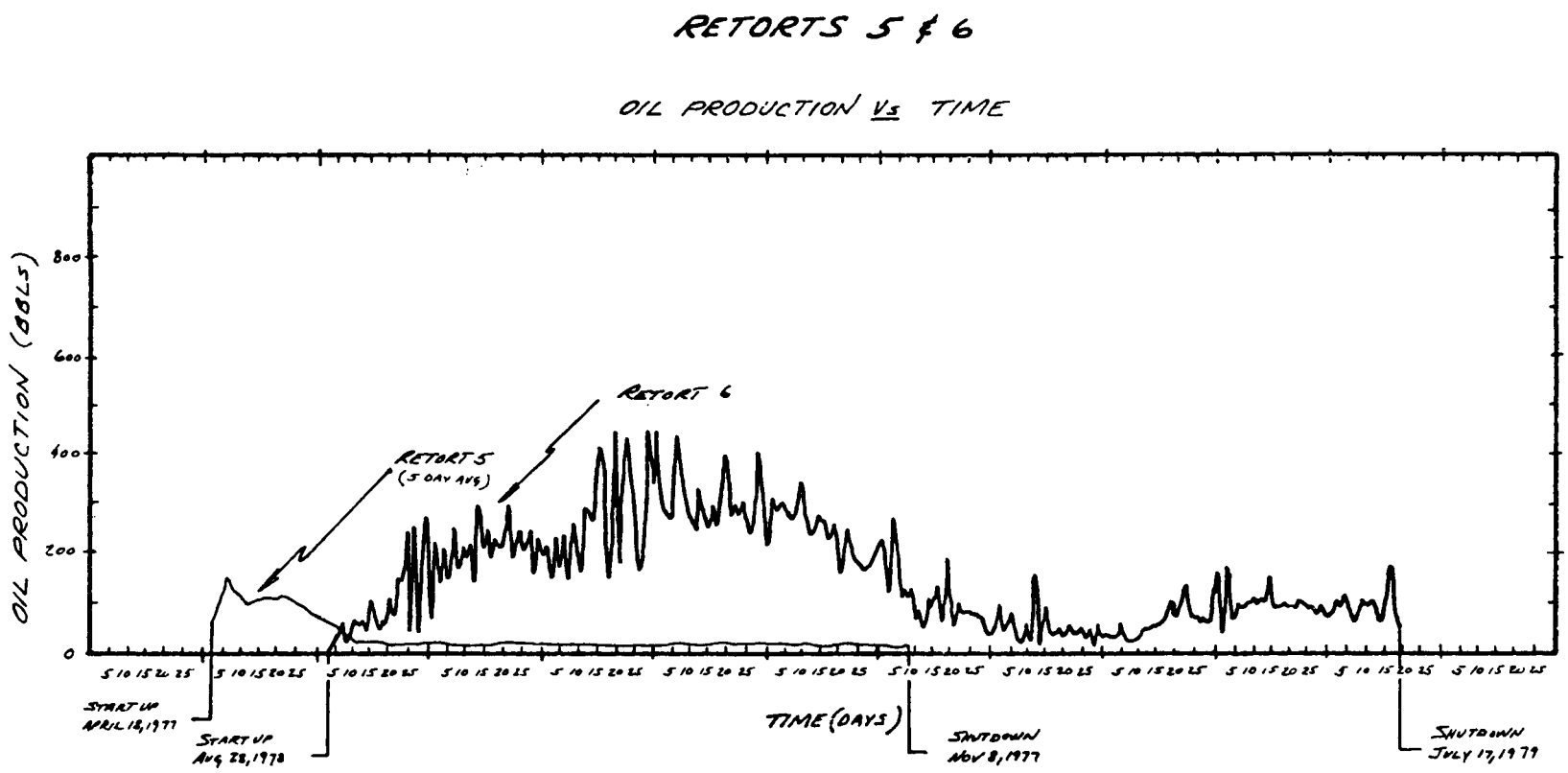


Figure 22. Comparison of the oil production from Retorts 5 and 6.

Retort 6, previously reported data were updated and are presented here. Details on sample collection methods were given in the annual reports. The following discussions are on Retort 6 data.

a. Raw Shale Analysis

The table below gives the general raw shale analysis in weight percent of a composite made from the LW-109 core taken near Retort 6.

TABLE IX
RAW SHALE ANALYSIS OF LW-109 CORE COMPOSITE

	Wt. %
Hydrogen	1.30
Organic Carbon	7.2
Carbonate	26.3
Ash	70.8
Nitrogen	0.24
Sulfur	0.44
Moisture	0.17
BTU Content *	1100 BTU/lb

* Gross calorific value less heat of formation of sulfuric acid from sulfur in the sample.

b. Oil Analysis

Oil samples were obtained at the oil load-out facility, Heater Treater area, for each 1000 barrels of production. The oil properties for the samples through the 38,000 barrel sample obtained by OOSI's analytical laboratory, are listed in Table X. The various ASTM methods used for the analysis are also noted on the table.

OOSI observed that the pour points for the samples were changing with time. A test program was conducted to

TABLE X
RETORT 6 HEATER TREATER OIL ANALYSES

TEST	BS & W %	API GRAVITY 60°F	POUR POINT * °F	KINEMATIC VISCOSITY 100°F cST	CLEVELAND OPEN CUP FLASH & FIRE °F	PENSKY MARTIN FLASH POINT °F	SULFUR %	HEATING VALUE BTU/lb	ASPHALTENE %	NITROGEN %
Reference / Sample	ASTM-D-96-23	ASTM-D-1298-23	ASTM-D-97-23	ASTM-D-445-23	ASTM-D-92-23	ASTM-D-93-23	ASTM-D-129-23	ASTM-D-240-23	UOP-614-68	ASTM-D-3228-2
1,000 Bbl	Sample emulsion could not be broken; lab unable to determine oil properties									
2,000 Bbl	0.2	23.1	0	27.47	Flash 225 Fire 235	202	0.72	18,800	0.28	1.10
3,000 Bbl	0.2	23.4	5	27.58	Flash 220 Fire 240	208	0.65	18,700	0.68	0.98
4,000 Bbl	0.2	22.5	5	31.61	Flash 235 Fire 245	208	0.63	18,500	0.29	1.14
5,000 Bbl	0.2	22.2	10	37.75	Flash 235 Fire 250	204	0.58	18,700	0.26	1 21
6,000 Bbl	0.2	22.0	0	41.02	Flash 230 Fire 250	212	0.67	18,800	0.52	1.18
7,000 Bbl	0.1	22.1	5	44.38	Flash 230 Fire 250	215	0.55	18,900	0.59	1.42
8,000 Bbl	0.3	22.7	10	46.41	Flash 230 Fire 250	211	0.53	18,800	0.40	1.36
9,000 Bbl	0.1	22.4	5	43.72	Flash 230 Fire 225	216	0.55	18,700	0.32	1.36
10,000 Bbl	0.3	22.9	60	44.08	Flash 235 Fire 225	216	0.49	18,900	0.34	1.40
11,000 Bbl	0.1	23.4	40	39.48	Flash 220 Fire 245	194	0.54	18,700	0.32	1.52
12,000 Bbl	0.2	22.6	35	40.33	Flash 220 Fire 240	192	0.47	18,800	0.53	1.43
13,000 Bbl	0.1	23.0	45	35.49	Flash 225 Fire 240	191	0.42	19,000	0.53	1.45
14,000 Bbl	0.2	22.8	55	43.70	Flash 220 Fire 235	193	0.51	18,500	0.26	1.47
15,000 Bbl	0.3	23.3	60	39.17	Flash 220 Fire 230	185	0.45	18,800	0.53	1.44
16,000 Bbl	0.1	23.2	55	41.72	Flash 215 Fire 235	187	0.39	18,800	0.57	1.43
17,000 Bbl	0.1	23.5	60	39.73	Flash 220 Fire 235	188	0.38	18,900	0.56	1.44
18,000 Bbl	0.2	23.9	75	37.06	Flash 220 Fire 235	192	0.49	18,800	0.30	1.44
19,000 Bbl	0.1	23.8	70	33.18	Flash 225 Fire 240	194	0.48	18,800	0.24	1.45
20,000 Bbl	0.1	24.1	75	33.33	Flash 225 Fire 235	200	0.54	18,500	0.33	1.44

*Changes in pour point being investigated.

TABLE X (continued)
RETORT 6 HEATER TREATER OIL ANALYSES

TEST	BS & W %	API GRAVITY 60°F	POUR POINT °F	KINEMATIC VISCOSITY @100°F cST/@140°	CLEVELAND OPEN CUP FLASH & FIRE °F	PENSKY MARTIN FLASH POINT °F	SULFUR %	HEATING VALUE BTU/lb	ASPHALTENE %	NITROGEN %
Reference Sample	ASTM-D-96-23	ASTM-D-1298-23	ASTM-D-97-23	ASTM-D-445-23	ASTM-D-92-23	ASTM-D-93-23	ASTM-D-129-23	ASTM-D-240-20	UOP-614-68	ASTM-D-3228-25
21,000 Bbl	0.1	24.0	60	31.00/12.99	Flash 220 Fire 240	201	0.45	18,700	0.39	1.46
22,000 Bbl	0.1	23.9	60	30.49/12.69	Flash 225 Fire 250	212	0.78	18,900	0.37	1.45
23,000 Bbl	0.2	23.8	55	29.50/12.32	Flash 230 Fire 255	208	0.77	18,900	0.14	1.40
24,000 Bbl	0.1	24.0	60	29.10/12.29	Flash 235 Fire 265	205	0.75	18,800	0.18	1.36
25,000 Bbl	0.1	23.9	60	31.96/13.22	Flash 240 Fire 275	212	0.82	18,800	0.32	1.41
26,000 Bbl	0.1	23.5	60	32.26/13.13	Flash 240 Fire 280	214	0.85	18,800	0.33	1.41
27,000 Bbl	0.1	24.0	60	29.21/12.27	Flash 250 Fire 280	209	0.57	18,900	0.31	1.41
28,000 Bbl	0.1	24.1	65	27.60/11.94	Flash 235 Fire 260	216	0.73	18,800	0.40	1.41
29,000 Bbl	0.1	24.1	55	26.71/11.57	Flash 240 Fire 260	212	0.82	18,900	0.28	1.40
30,000 Bbl	0.1	24.4	60	26.46/11.46	Flash 245 Fire 265	214	0.55	18,800	0.48	1.40
31,000 Bbl	0.2	24.0	65	31.11/12.65	Flash 240 Fire 260	215	0.70	18,800	0.29	1.43
32,000 Bbl	0.1	24.3	60	29.05/12.16	Flash 245 Fire 260	220	0.72	18,900	0.30	1.36
33,000 Bbl	0.1	24.2	60	28.05/10.90	Flash 240 Fire 265	216	0.68	18,800	0.37	1.37
34,000 Bbl	0.2	24.3	55	28.30/12.00	Flash 240 Fire 265	218	0.67	18,800	0.32	1.36
35,000 Bbl	0.1	24.2	60	26.20/11.77	Flash 245 Fire 270	222	0.67	18,800	0.38	1.40
36,000 Bbl	0.25	23.8	45	26.68/10.67	Flash 260 Fire 280	>230	0.66	18,700	0.15	1.30
37,000 Bbl	0.15	24.3	45	24.24/9.82	Flash 270 Fire 290	>230	0.60	18,800	0.14	1.29
38,000 Bbl	0.20	24.5	50	22.42/9.36	Flash 260 Fire 290	233	0.72	18,800	0.14	

determine the extent of and the trends in the changes in pour point. Kinematic viscosity was also investigated. Thirty samples were retested; it was found that the changes appeared random and no pattern could be detected.

Oil samples were also shipped to Occidental Research Corporation for analysis. The data obtained are presented in Table XI.

c. Offgas Analysis

The average offgas analyses from ignition, on August 28, 1978, through the steam injection test (run after shutdown), completed August 7, 1979, are listed on Table XII. Measurements for carbonyl sulfide (COS), sulfur dioxide (SO_2) and ethane (C_6H_6) were taken, but for the most part the gases were undetected and therefore not listed on the table. Carbonyl sulfide ranged between 1 and 40 ppm from March 12 through May 1979, with the general trend being downward.

The percent of hydrogen, carbon monoxide, methane and carbon dioxide (from the tables) in the offgas vs. time are plotted in Figures 23 through 26 for the entire retort operation. Additionally, the dry offgas flow rate, offgas temperature and net heating value vs. time are plotted in Figures 27, 28 and 29. The start up date when steam was introduced to the retort, dates when secondary combustion and UIL injections were begun, and date the shutdown and steam injection testing occurred are noted on the plots. The upset conditions during September 1978 are easily seen by the early peaks on the plots. Clearly, the curves show the return to normal conditions at the end of September.

RETORT 6 PRODUCT OIL D-1160 DISTILLATION RESULTS

Volume % Distilled (Temperature in °F)

ample, Bbl.	First Drop	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%	Last Fraction	Residue
)00	142	248	267	287	301	331	362	411	486	559	---	91% @ 629	8.8
)00	311	450	480	517	550	601	632	669	755	827	925	93% @ 927	6.0
)00	304	451	495	539	589	629	679	726	775	837	907	93% @ 912	7.1
)00	328	459	499	553	597	643	692	745	795	849	---	93% @ 930	7.3
)00	363	470	504	553	605	650	706	763	815	861	---	89% @ 916	10.9
)00	331	454	501	556	604	656	715	770	814	866	---	90.5% @ 902	10.6
),000	326	459	495	553	605	660	715	765	819	874	---	91% @ 933	9.3
,000	326	432	487	549	597	651	709	761	816	872	---	92% @ 933	10.0
),000	211	434	483	542	592	641	693	744	795	845	917	91.5% @ 927	9.4
,000	348	461	498	557	602	649	703	751	799	849	924	94.5% @ 954	6.0
),000	280	440	479	545	604	627	672	723	774	812	897	97% @ 942	5.01
,000	417	481	515	568	623	649	692	735	772	819	879	97% @ 943	4.1
,000	403	497	523	560	599	634	675	686	770	817	876	98% @ 902	4.5
,000	402	512	556	620	637	668	673	749	789	829	890	98.5% @ 961	2.3

TABLE XI (continued)
RETORT 6 HEATER TREATER PRODUCT OIL D-1160 DISTILLATION DATA*

Sample Bbls	Initial Boiling Pt. °F	Volume Percent Distilled (Temperature in °F) 5%	10%	20%	30%	40%	50%	60%	70%	80%	90%
2,000	378	470.8	497.0	545.4	579.2	614.8	655.0	706.0	768.0	848.0	924.4
3,000	384.4	455.8	494.2	539.0	577.4	610.4	655.0	706.0	765.0	844.4	914.4
4,000	384.4	462.2	505.2	550.0	587.4	627.6	673.2	722.4	783.8	848.0	916.2
5,000	376.2	466.8	505.2	562.6	613.0	660.4	716.0	769.8	822.6	876.2	922.2
6,000	371.6	462.2	505.2	560.0	610.4	656.8	706.0	757.0	809.8	866.2	924.4
7,000	365.2	458.2	494.2	558.2	606.6	656.8	710.6	763.4	818.0	880.8	922.2
8,000	389.0	470.8	507.0	564.6	613.0	660.4	716.0	763.4	826.2	880.8	919.8
9,000	379.8	468.6	507.0	560.0	608.4	656.8	712.4	771.6	824.4	878.0	919.8
10,000	379.8	467.6	507.0	566.4	617.2	665.0	720.6	775.4	826.2	880.8	938.0
11,000	376.2	466.8	500.6	547.4	606.6	658.6	710.6	761.6	819.8	876.2	939.2
12,000	379.8	466.8	507.0	564.6	613.0	665.0	722.4	778.0	828.0	880.8	936.2
13,000	371.6	454.0	494.2	558.2	610.4	656.8	716.0	771.6	826.2	880.8	938.0
14,000	365.2	454.0	497.0	556.4	606.6	655.0	710.0	768.0	822.6	876.2	928.0
15,000	376.2	466.8	505.2	562.6	613.0	660.4	716.0	769.8	822.6	876.2	922.2
16,000	389.0	466.8	503.4	560.0	613.0	663.2	720.6	773.4	828.0	884.4	933.4
17,000	362.4	455.8	494.2	551.8	606.6	656.8	710.6	768.0	824.4	878.0	928.0
18,000	376.2	451.4	490.2	551.8	604.8	655.0	704.2	759.8	816.2	910.6	929.8
19,000	379.8	458.2	492.4	551.8	600.2	652.2	702.4	755.2	809.8	931.6	949.6

* Performed by Chas. Martin Inspectors of Petroleum, Inc.

TABLE XI (continued)
RETORT 6 HEATER TREATER PRODUCT OIL D-1160 DISTILLATION DATA

Sample Bbls	Initial Boiling Pt. °F	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%
20,000	389.0	475.0	513.4	566.4	616.6	665.0	716.0	765.2	818.0	872.6	936.2
21,000	389.0	468.6	507.0	562.6	613.0	658.6	710.6	763.4	812.6	866.2	924.4
22,000	371.6	454.0	494.2	550.0	598.4	644.0	694.2	743.4	791.6	844.4	904.4
22,000	411	475	497	547	607	657	700	747	803	856	908
23,000	389.0	468.6	507.0	562.6	610.4	658.6	708.6	759.8	809.8	860.8	919.8
24,000	378.0	468.6	505.2	560.0	610.4	658.6	708.6	761.2	808.0	860.8	918.0
25,000	376.2	466.8	505.2	562.6	610.4	658.6	710.6	768.0	824.4	872.6	924.4
26,000	376.2	458.2	498.8	551.8	598.4	644.0	691.4	743.4	796.2	848.0	912.6
27,000	388.4	475.0	516.2	566.4	614.8	656.8	706.0	755.2	806.2	856.2	912.6
28,000	408.2	486.0	518.0	569.2	613.0	656.8	706.0	753.4	804.4	852.6	912.6
29,000	411.0	486.0	519.8	571.0	613.0	656.8	702.4	747.0	802.2	852.6	912.6

TABLE XII
RETORT 6 OFFGAS ANALYSES

November 1978

DATE 1978	H_2	N_2	O_2	CO	CH_4	CO_2	$C_2^=$	C_2	$C_3^=$	C_3	IC_4	BUT-I	NC_4	C T	IC_5	NC_5	C_6	C_7	H_2S
	% Volume																		PPM
11-1	5.566	57.330	.053	.203	1.223	34.549	.079	.172	.051	.065	.006	.019	.033	.002	.001	.003	.001	.002	785
11-2	5.130	58.430	.054	.204	1.183	33.916	.066	.165	.046	.066	.006	.018	.032	0	.001	.005	.004	.002	719
11-3	5.412	57.158	.081	.209	1.209	34.774	.068	.164	.046	.065	.006	.019	.034	0	.001	.004	.003	.001	638
11-4	5.315	57.482	.104	.217	1.189	34.585	.068	.166	.043	.058	.008	.021	.035	.001	.002	.005	.004	.001	767
11-5	5.340	57.249	.187	.233	1.211	34.830	.070	.166	.044	.061	.007	.021	.037	0	.002	.004	.006	.001	780
11-6	5.129	57.461	.077	.242	1.188	34.779	.072	.164	.053	.069	.007	.022	.038	0	.001	.005	.003	.001	722
11-7	5.145	57.194	.069	.261	1.165	35.031	.066	.161	.049	.069	.007	.021	.034	0	.001	.005	.002	.001	770
11-8	5.408	56.532	.087	.259	1.172	35.422	.067	.162	.041	.062	.007	.022	.039	.004	.002	.005	.003	.002	855
11-9	5.272	56.639	.054	.265	1.157	35.509	.069	.162	.048	.065	.007	.023	.039	0	.002	.005	.005	.002	851
11-10	5.241	57.019	.049	.260	1.147	35.191	.070	.161	.049	.066	.006	.020	.034	0	.001	.005	.006	.002	866
11-11	5.439	56.653	.030	.253	1.157	35.474	.068	.163	.047	.062	.005	.018	.032	0	.001	.004	.003	.002	887
11-12	5.072	57.916	.044	.253	1.103	34.527	.064	.159	.047	.057	.004	.018	.032	0	.001	.004	.006	.001	862
11-13	5.329	56.432	.043	.247	1.108	35.779	.065	.159	.046	.063	.006	.018	.032	0	.001	.004	.003	.002	823
11-14	5.436	56.216	.143	.247	1.129	35.710	.066	.160	.048	.067	.005	.022	.046	.001	.002	.004	.002	.002	818
11-15	5.426	56.173	.067	.246	1.116	35.901	.063	.158	.048	.066	.005	.018	.043	0	.002	.003	.002	.003	839
11-16	5.227	56.748	.105	.248	1.094	35.499	.063	.156	.049	.067	.005	.018	.043	0	.001	.004	.002	.003	814
11-17	5.258	56.706	.052	.257	1.090	35.571	.060	.155	.047	.067	.005	.018	.043	0	.001	.004	.002	.003	809
11-18	5.171	56.980	.075	.269	1.080	35.343	.059	.154	.042	.068	.006	.021	.050	0	.003	.005	.002	.004	786
11-19	5.226	56.620	.067	.236	1.092	35.639	.062	.157	.047	.064	.006	.022	.053	0	.002	.006	.001	.004	796
11-20	5.275	56.418	.054	.296	1.107	35.742	.064	.158	.047	.019	.007	.025	.060	0	.002	.006	.004	.004	789
11-21	5.341	56.225	.041	.303	1.133	35.847	.066	.163	.048	.069	.007	.024	.058	0	.001	.007	.002	.005	791
11-22	5.379	56.817	.045	.289	1.153	35.195	.067	.164	.030	.066	.007	.026	.062	0	.002	.007	.002	.005	851
11-23	5.446	56.504	.040	.295	1.152	35.410	.071	.164	.052	.067	.007	.027	.064	0	.001	.007	.004	.004	843
11-24	5.463	56.280	.046	.297	1.151	35.644	.075	.165	.051	.064	.007	.027	.064	0	.002	.006	.003	.004	850
11-25	5.389	56.228	.034	.306	1.140	35.801	.073	.164	.049	.064	.006	.023	.055	0	.002	.006	.003	.004	875
11-26	5.304	56.448	.029	.312	1.134	35.648	.074	.162	.052	.065	.005	.020	.047	0	.002	.005	.003	.004	884
11-27	5.485	56.012	.024	.326	1.155	35.905	.078	.164	.055	.069	.005	.020	.047	0	.001	.005	.002	.003	*
11-28	5.652	55.863	.027	.334	1.185	35.830	.080	.169	.055	.067	.005	.020	.049	0	.001	.004	.002	.003	924
11-29	5.664	56.304	.034	.336	1.194	35.343	.077	.171	.056	.072	.005	.020	.050	.009	.001	.004	.002	.003	952
11-30	5.287	57.988	.045	.392	1.156	34.030	.075	.165	.052	.066	.004	.019	.049	.003	.001	.003	.001	.001	*

December 1978

Date 1978	H_2	N_2	O_2	CO	CH_4	CO_2	$C_2^=$	C_2	$C_3^=$	C_3	IC_4	BUT-I	NC_4	C T	IC_5	NC_5	C_6	C_7	H_2S
	% Volume																		PPM
12-1	5.490	57.372	.020	.402	1.186	34.430	.075	.169	.051	.068	.004	.021	.055	.005	.002	.003	.001	.001	940
12-2	5.516	57.293	.161	.420	1.231	34.287	.083	.173	.058	.060	.005	.022	.056	.005	.003	.002	.001	.001	912
12-3	5.710	56.940	.032	.464	1.259	34.291	.088	.180	.057	.071	.004	.020	.053	.004	.002	.002	.001	.001	*
12-4	5.964	56.683	.060	.492	1.304	34.332	.089	.188	.061	.075	.005	.023	.058	.005	.002	.003	.001	.002	984
12-5	6.017	56.590	.115	.527	1.293	34.275	.091	.188	.063	.076	.005	.023	.060	.005	.001	.003	.001	.002	829
12-6	5.921	56.625	.118	.544	1.268	34.272	.088	.186	.060	.074	.005	.025	.065	.005	.001	.003	.001	.002	*
12-7	5.871	56.814	.031	.552	1.222	34.350	.082	.182	.059	.074	.005	.025	.067	.005	.002	.005	.001	.001	964
12-8	5.501	57.858	.028	.578	1.183	33.755	.077	.177	.057	.073	.006	.024	.066	.005	.002	.004	.001	.001	926
12-9	4.837	59.169	.051	.769	1.100	32.828	.076	.170	.055	.070	.005	.025	.067	.005	.002	.003	.001	.002	839
12-10	5.536	56.589	.090	.728	1.179	34.641	.078	.178	.059	.074	.006	.027	.072	.005	.002	.005	.001	.002	890
12-11	5.912	55.953	.080	.677	1.244	34.955	.083	.186	.060	.078	.006	.028	.075	.006	.001	.003	.001	.002	*
12-12	6.148	55.688	.071	.682	1.272	35.017	.081	.191	.059	.074	.006	.022	.055	.005	.001	.003	.001	0	973
12-13	6.615	54.939	.082	.624	1.327	35.283	.084	.200	.155	.087	.008	.028	.063	.003	.001	.001	.001	.001	982
12-14	6.453	55.435	.134	.626	1.332	34.681	.089	.209	.151	.111	.013	.038	.068	0	0	0	0	0	1008
12-15	6.810	55.249	.111	.630	1.378	34.637	.084	.216	.063	.081	.010	.034	.055	.005	.003	.004	.001	.002	1025
12-16	6.909	54.693	.081	.642	1.397	34.790	.087	.223	.061	.042	.011	.034	.048	.005	.005	.002	.002	.002	1070
12-17	7.209	54.538	.093	.700	1.440	34.821	.095	.235	.080	.068	.006	.019	.027	.001	.006	.006	.001	0	1083
12-18	7.735	53.704	.028	.704	1.501	35.088	.091	.246	.072	.098	.012	.037	.047	.007	.003	.005	.002	.002	1236
12-19	7.686	53.086	.090	.670	1.443	33.736	.088	.233	.067	.089	.017	.047	.059	.007	.002	.005	.001	.001	*
12-20	8.390	55.119	.007	.300	1.771	32.835	.072	.210	.068	.165	.015	.040	.040	.006	.003	.005	.003	.002	645
12-21	8.166	55.010	.020	.316	1.754	33.501	.073	.207	.071	.110	.019	.043	.035	.005	.003	.007	.003	.002	665
12-22	8.231	55.352	.049	.319	1.627	33.221	.071	.201	.067	.103	.013	.033	.042	.003	.002	.006	.003	.002	727
12-23	7.079	58.055	.050	.533	1.238	31.906	.064	.168	.055	.079	.009	.032	.043	.003	.002	.004	.002	.001	603
12-24	7.248	56.105	.038	.608	1.324	33.523	.076	.181	.062	.087	.011	.040	.052	.007	.002	.003	.002	.001	517
12-25	7.333	55.192	.026	.622	1.411	34.260	.084	.191	.065	.087	.013	.043	.057	.006	.002	.004	.001	.001	540
12-26	7.969	58.814	.037	.638	1.376	33.969	.084	.190	.063	.086	.015	.043	.044	.006	.004	.004	.004	.001	540
12-27	7.806	54.690	.044	.564	1.427	34.263	.080	.197	.067	.094	.012	.038	.051	.005	.002	.006	.001	.002	637
12-28	7.564	55.315	.033	.555	1.394	33.978	.077	.194	.064	.092	.012	.036	.047	.005	.002	.006	.001	.001	710
12-29	6.719	57.675	.035	.670	1.312	32.376	.074	.186	.070	.092	.011	.033	.045	.004	.002	.006	.002	.001	650
12-30	7.317	55.452	.027	.643	1.369	34.021	.073	.192	.061	.090	.011	.031	.044	.004	.002	.005	.002	.001	661
12-31	7.254	55.727	.044	.625	1.378	33.763	.072	.194	.062	.094	.013	.036	.049	.004	.004	.005	.003	.001	580

* Equipment malfunction, no data.

TABLE XII (continued)
RETORT 6 OFFGAS ANALYSES

January 1979

Date	H_2	N_2	O_2	CO	CH_4	CO_2	$C_2^=$	C_2	$C_3^=$	C_3	IC_4	BUT-I	NC_4	C T	IC_5	NC_5	C_6	C_7	H_2S
1979	% Volume																		PPM
1/1	6.215	58.407	.056	.742	1.287	32.362	.069	.188	.061	.092	.013	.036	.050	.004	.003	.006	.003	.002	489
1/2	6.076	57.530	.061	.844	1.296	32.965	.072	.194	.064	.093	.013	.037	.050	.004	.002	.005	.003	.001	677
1/3	6.441	56.351	.063	.890	1.366	33.654	.074	.204	.067	.098	.014	.039	.052	.004	.003	.006	.003	.002	493
1/4	7.018	55.869	.088	.84	1.396	33.556	.077	.207	.068	.099	.014	.027	.053	.004	.004	.005	.003	.002	528
1/5	7.132	56.524	.117	.849	1.365	33.009	.075	.202	.066	.098	.014	.039	.052	.004	.003	.007	.004	.002	594
1/6	7.221	56.633	.130	.825	1.372	32.574	.073	.204	.066	.099	.012	.034	.047	.004	.003	.006	.003	.002	510
1/7	7.085	57.304	.225	.910	1.319	31.955	.070	.196	.064	.096	.010	.028	.035	.003	.003	.005	.002	.001	534
1/8	7.508	55.529	.145	.852	1.393	33.374	.071	.202	.063	.097	.012	.034	.047	.005	.002	.006	.001	.001	617
1/9	7.546	55.851	.092	.843	1.418	33.016	.073	.204	.068	.101	.015	.043	.057	.006	.002	.006	.003	.001	590
1/10	7.244	57.088	.091	.854	1.365	32.113	.068	.171	.099	.110	.020	.044	.042	.006	.003	.005	.003	.001	600
1/11	7.143	56.489	.108	.923	1.381	32.701	.071	.213	.066	.097	.012	.036	.055	.004	.002	.009	.002	.001	840
1/12	7.650	55.987	.125	.911	1.416	32.659	.070	.219	.066	.098	.014	.037	.050	.004	.002	.009	.002	.001	810
1/13	7.605	56.324	.108	.886	1.416	32.402	.071	.219	.065	.093	.014	.037	.051	.005	.002	.008	.002	.001	1102
1/14	7.646	56.282	.105	.891	1.431	32.385	.072	.221	.069	.100	.012	.031	.044	.003	.002	.006	.003	.002	1189
1/15	7.649	56.414	.081	.890	1.435	32.261	.074	.224	.067	.098	.013	.035	.047	.004	.002	.005	.002	.002	
1/16	6.864	56.596	.127	.884	1.451	32.438	.077	.245	.065	.097	.013	.035	.047	.004	.002	.008	.003	.002	1202
1/17	6.59	57.375	.172	.881	1.469	32.24	.077	.255	.068	.1	.014	.036	.049	.003	.002	.009	.003	.002	1186
1/18	6.641	57.199	.079	.889	1.466	32.428	.077	.256	.069	.101	.014	.036	.049	.003	.001	.009	.002	.002	1225
1/19	7.097	57.172	.085	.881	1.448	32.024	.075	.255	.068	.101	.014	.035	.048	.003	.001	.009	.003	.002	1194
1/20	7.01	57.204	.101	.901	1.427	32.013	.075	.253	.068	.100	.014	.035	.048	.002	.002	.009	.003	.002	1253
1/21	7.033	57.580	.102	.957	1.418	31.610	.076	.254	.068	.100	.014	.035	.049	.003	.001	.009	.003	.002	1244
1/22	7.320	56.872	.083	.942	1.438	32.042	.078	.258	.069	.102	.014	.037	.051	.003	.001	.008	.003	.002	1306
1/23	7.222	56.995	.092	.940	1.416	31.913	.072	.253	.068	.100	.015	.038	.052	.003	.002	.010	.003	.003	1313
1/24	7.410	56.618	.093	.952	1.430	32.172	.080	.256	.070	.101	.016	.042	.057	.004	.002	.009	.004	.003	1325
1/25	7.269	56.876	.078	.908	1.429	32.111	.079	.259	.070	.102	.018	.046	.064	.001	.001	.009	.004	.003	NA
1/26	7.355	56.915	.078	.902	1.405	32.028	.079	.249	.070	.102	.015	.039	.054	.005	.002	.008	.004	.003	
1/27	7.325	56.891	.080	.910	1.378	32.123	.079	.243	.069	.101	.013	.034	.047	.005	.001	.007	.003	.003	
1/28	6.873	57.863	.089	.980	1.302	31.623	.080	.233	.067	.097	.010	.027	.048	.004	.001	.006	.003	.002	
1/29	6.913	57.420	.080	1.044	1.318	31.956	.082	.235	.069	.097	.010	.028	.039	.004	.001	.006	.003	.002	
1/30	7.057	57.024	.092	1.022	1.333	32.203	.084	.161	.069	.097	.010	.028	.040	.004	.001	.006	.002	.002	
1/31	7.268	56.756	.083	1.003	1.346	32.250	.085	.244	.070	.100	.013	.036	.048	.004	.001	.007	.003	.002	

February 1979

Date	H_2	N_2	O_2	CO	CH_4	CO_2	$C_2^=$	C_2	$C_3^=$	C_3	IC_4	BUT-I	NC_4	C T	IC_5	NC_5	C_6	C_7	H_2S
1979	% Volume																		PPM
2/1	8.599	51.819	.046	1.045	1.884	34.795	.091	.344	.090	.125	.018	.045	.068	.005	.003	.009	.003	.003	
2/2	7.112	59.453	.101	.899	1.215	29.938	.071	.226	.063	.092	.012	.031	.046	.004	.002	.007	.003	.001	
2/3	7.237	57.474	.107	1.029	1.274	31.586	.074	.237	.066	.096	.013	.034	.049	.004	.002	.007	.003	.001	
2/4	7.907	55.725	.088	1.024	1.576	32.301	.078	.291	.076	.118	.017	.041	.061	.005	.002	.010	.003	.001	
2/5	7.112	58.102	.087	1.039	1.230	31.148	.068	.220	.063	.094	.014	.035	.050	.004	.002	.010	.003	.002	
2/6	7.306	56.887	.075	1.078	1.308	31.866	.071	.245	.067	.101	.015	.039	.056	.004	.002	.010	.003	.002	
2/7	7.370	57.288	.092	1.092	1.327	31.577	.070	.250	.067	.103	.017	.044	.063	.005	.002	.010	.004	.003	
2/8	7.370	57.110	.077	1.106	1.328	31.653	.070	.252	.068	.103	.019	.050	.070	.005	.002	.012	.004	.003	
2/9	7.414	57.008	.073	1.121	1.341	31.721	.072	.255	.070	.105	.020	.052	.074	.006	.002	.013	.005	.003	
2/10	7.517	56.985	.085	1.100	1.346	31.604	.072	.256	.069	.105	.020	.053	.074	.006	.002	.011	.004	.004	2367
2/11	7.433	57.436	.122	1.103	1.328	31.231	.072	.253	.068	.104	.017	.045	.065	.005	.002	.011	.005	.002	2303
2/12	7.629	56.935	.103	1.118	1.393	31.484	.073	.264	.067	.102	.016	.040	.059	.005	.003	.007	.004	.003	
2/13	7.654	57.259	.094	1.092	1.372	31.176	.073	.260	.071	.107	.016	.042	.062	.005	.003	.009	.005	.002	2395
2/14	7.721	57.172	.090	1.070	1.387	31.216	.072	.264	.071	.107	.017	.042	.062	.005	.003	.009	.005	.004	
2/15	7.603	57.575	.092	1.048	1.344	31.014	.070	.256	.068	.105	.016	.041	.061	.005	.003	.008	.006	.002	
2/16	7.516	57.892	.087	1.045	1.306	30.836	.071	.249	.068	.103	.014	.035	.053	.004	.002	.008	.005	.003	2327
2/17	7.446	57.731	.088	1.013	1.332	31.078	.073	.251	.068	.103	.014	032	.050	.004	.002	.006	.004	.002	2256
2/18	7.403	57.999	.088	1.039	1.319	30.879	.073	.248	.067	.102	.008	.022	.033	.002	.001	.005	.003	.001	2242
2/19	7.403	57.826	.081	1.059	1.322	31.018	.073	.247	.066	.102	.011	.028	.043	.004	.002	.006	.004	.002	2242
2/20	7.483	57.807	.089	1.063	1.325	30.920	.072	.248	.066	.102	.014	.034	.053	.004	.002	.006	.004	.002	
2/21	7.662	57.765	.082	1.063	1.328	30.772	.072	.249	.067	.103	.016	.039	.057	.005	.002	.006	.005	.003	2399
2/22	7.433	58.006	.079	1.032	1.316	30.833	.071	.244	.065	.101	.014	.036	.052	.004	.001	.005	.005	.003	2325
2/23	7.171	58.608	.089	1.022	1.241	30.603	.069	.230	.063	.095	.013	.033	.046	.004	.001	.004	.004	.003	2114
2/24	6.411	59.370	.092	1.111	1.162	30.606	.072	.217	.062	.089	.012	.032	.044	.004	.006	.004	.003	.003	2005
2/25	6.190	59.479	.092	1.203	1.154	30.704	.073	.215	.062	.088	.012	.031	.042	.004	.001	.004	.004	.002	2296
2/26	6.349	58.942	.087	1.241	1.174	30.972	.075	.216	.063	.089	.010	.028	.039	.004	.001	.004	.005	.001	2035
2/27	6.399	59.092	.106	1.262	1.182	30.706	.078	.220	.063	.088	.011	.030	.041	.004	.001	.004	.004	.001	
2/28	6.68	58.876	.087	1.285	1.202	30.609	.077	.226	.063	.089	.012	.032	.044	.004	.001	.004	.003	.002	2347

TABLE XII (continued)
RETORT 6 OFFGAS ANALYSES

March 1979

Date 1979	H_2	N_2	O_2	CO	CH_4	CO_2	$C_2^=$	C_2	$C_3^=$	C_3	IC_4	BUT-I	NC_4	C T	IC_5	NC_5	C_6	C_7	H_2S
	% Volume																		PPM
3/1	6.334	59.249	.087	1.275	1.119	30.557	.075	.219	.063	.088	.011	.031	.043	.004	.001	.004	.004	.001	2237
3/2	6.950	57.209	.078	1.309	1.399	31.767	.079	.254	.069	.104	.013	.034	.049	.005	.001	.004	.005	.002	2665
3/3	7.920	55.905	.051	1.115	1.749	31.869	.077	.317	.078	.131	.018	.041	.063	.006	.002	.005	.005	0	
3/4	6.063	63.184	.105	.960	1.007	27.420	.060	.184	.051	.075	.009	.025	.035	0	.001	.003	.003	0	2168
3/5	5.833	61.976	.093	1.207	1.040	28.656	.064	.191	.054	.078	.010	.026	.036	.001	.001	.003	.002	0	1854
3/6	5.154	63.272	.094	1.540	.985	27.761	.060	.184	.050	.075	.010	.025	.036	0	.001	.003	.004	0	
3/7	5.258	62.782	.084	1.738	.978	27.957	.057	.184	.050	.075	.009	.025	.035	0	.001	.003	.005	0	2182
3/8	5.260	66.092	.077	1.733	.973	27.793	.058	.180	.047	.072	.009	.024	.035	0	.001	.003	.006	0	1922
3/9	5.081	62.928	.082	1.782	.950	27.984	.054	.174	.046	.071	.009	.023	.034	0	.001	.003	.003	0	1872
3/10	4.907	62.813	.086	1.854	.948	28.206	.052	.174	.046	.069	.009	.023	.032	0	.001	.003	.004	.001	1774
3/11	4.900	62.946	.086	1.947	.970	28.415	.057	.178	.049	.071	.008	.022	.030	0	.001	.003	.004	0	1751
3/12	5.468	58.511	.067	2.265	1.283	30.992	.063	.238	.062	.096	.010	.025	.037	.002	.001	.003	.004	0	1890
3/13	7.783	51.651	.049	2.218	1.909	34.987	.069	.350	.081	.146	.017	.036	.058	.006	.002	.005	.006	0	2333
3/14	8.318	53.887	.068	1.692	1.862	32.768	.063	.337	.076	.140	.018	.037	.062	.006	.002	.006	.006	0	2315
3/15	8.453	55.644	.11	1.421	1.761	31.233	.057	.316	.069	.131	.018	.035	.061	.005	.002	.005	.005	.0004	
3/16	8.304	57.741	.066	1.272	1.711	30.024	.055	.305	.065	.127	.018	.034	.059	.005	.002	.005	.006	0	
3/17	8.036	59.129	.082	1.163	1.606	28.633	.051	.287	.054	.129	.017	.033	.057	.005	.002	.005	.006	.001	
3/18	7.771	59.963	.075	1.107	1.538	28.009	.050	.276	.048	.105	.019	.036	.062	.005	.002	.005	.007	.001	
3/19	7.595	60.717	.079	1.058	1.493	27.691	.048	.269	.058	.128	.019	.036	.062	.005	.002	.005	.007	0	
3/20	7.659	60.639	.075	1.074	1.522	27.603	.048	.273	.058	.169	.019	.036	.062	.005	.002	.005	.007	0	2171
3/21	8.257	60.395	.068	1.175	1.664	26.971	.050	.289	.059	.217	.019	.036	.061	.005	.002	.005	.007	.001	2278
3/22	8.187	61.279	.079	1.244	1.711	25.896	.050	.292	.060	.249	.017	.030	.052	.005	.002	.005	.007	0	2225
3/23	7.964	61.149	.072	1.315	1.702	25.850	.050	.299	.062	.248	.016	.027	.047	.004	.002	.005	.006	.001	2304
3/24	8.321	61.415	.069	1.372	1.720	25.575	.053	.306	.064	.264	.015	.027	.044	.004	.002	.005	.006	0	2393
3/25	7.916	61.699	.107	1.377	1.670	25.406	.054	.301	.065	.272	.014	.025	.043	.005	.007	.005	.006	0	2737
3/26	7.868	62.110	.074	1.323	1.492	25.636	.054	.273	.063	.257	.013	.024	.040	.004	.002	.004	.006	0	2186
3/27	7.634	61.547	.072	1.414	1.372	26.476	.051	.253	.059	.245	.011	.021	.035	.003	.001	.004	.005	0	2107
3/28	6.960	61.859	.086	1.594	1.224	26.874	.050	.228	.056	.232	.009	.017	.028	.001	.001	.003	.005	0	2021
3/29	6.701	59.207	.075	1.641	1.347	20.713	.047	.246	.057	.175	.011	.022	.037	.002	.001	.003	.005	.0004	
3/30	8.151	47.856	.065	1.828	2.154	38.724	.047	.351	.063	.147	.019	.031	.061	.006	.002	.006	.006	.001	2496
3/31	9.349	42.664	.062	1.688	2.308	42.684	.053	.351	.064	.143	.019	.031	.060	.006	.002	.006	.007	0	2498

April 1979

Date	H_2	N_2	O_2	CO	CH_4	CO_2	$C_2^=$	C_2	$C_3^=$	C_3	IC_4	BUT-I	NC_4	C T	IC_5	NC_5	C_6	C_7	H_2S
	% Volume																		PPM
4/1	9.657	42.914	.068	1.524	2.343	42.221	.056	.361	.065	.145	.019	.032	.061	.006	.002	.006	.007	0	2589
4/2	9.918	43.276	.112	1.446	2.429	41.538	.056	.380	.068	.153	.020	.032	.062	.006	.002	.006	.006	0	2747
4/3	8.966	44.074	.133	1.332	2.452	41.727	.056	.384	.069	.156	.021	.033	.063	.006	.002	.005	.006	0	2708
4/4	8.790	44.993	.127	1.277	2.419	41.065	.054	.384	.068	.156	.021	.033	.065	.005	.002	.005	.005	0	2673
4/5	9.647	45.691	.122	1.228	2.333	39.614	.051	.376	.065	.152	.022	.033	.066	.005	.002	.004	.005	0	2564
4/6	9.968	48.656	.116	1.072	2.093	36.793	.049	.342	.060	.137	.020	.031	.060	.005	.002	.004	.005	0	2474
4/7	7.712	55.483	.111	1.125	1.439	32.469	.040	.236	.045	.095	.012	.021	.039	.002	.001	.003	.004	0	2254
4/8	7.239	55.882	.115	1.369	1.361	32.898	.039	.222	.043	.089	.011	.020	.036	0	.001	.003	.004	0	2222
4/9	7.316	56.135	.106	1.570	1.358	32.436	.039	.222	.044	.089	.011	.019	.035	.001	.001	.003	.004	0	2323
4/10	7.354	56.754	.090	1.736	1.421	31.461	.038	.232	.048	.098	.012	.020	.037	0	.001	.003	.003	0	2402
4/11	6.219	58.262	.058	2.046	1.259	30.975	.033	.202	.037	.081	.011	.017	.031	0	.001	.002	.002	0	2293
4/12	6.067	57.493	.094	2.328	1.249	31.668	.032	.197	.036	.078	.011	.017	.032	0	.001	.003	.003	0	2220
4/13	7.426	54.627	.066	1.929	1.350	33.527	.037	.201	.038	.079	.011	.019	.034	0	.001	.003	.004	0	2106
4/14	7.462	54.923	.087	2.048	1.318	33.085	.038	.198	.039	.077	.011	.018	.032	.001	.001	.002	.004	0	1844
4/15	8.564	52.936	.116	1.859	1.344	34.132	.040	.199	.037	.066	.010	.019	.032	.001	.001	.003	.004	0	1886
4/16	8.519	53.014	.099	1.802	1.353	34.163	.040	.201	.030	.060	.010	.020	.033	.002	.001	.003	.004	0	1854
4/17	8.374	53.146	.143	1.845	1.387	34.050	.042	.207	.037	.062	.009	.022	.035	.002	.001	.003	.003	0	1901
4/18	8.271	51.617	.091	1.887	1.613	35.359	.047	.240	.037	.063	.011	.026	.043	.004	.001	.004	.002	0	1924
4/19	8.984	51.939	.113	1.759	1.656	34.433	.05	.245	.047	.085	.013	.025	.041	.003	.001	.003	.001	0	2118
4/20	9.631	52.04	.094	1.684	1.636	33.777	.051	.236	.049	.089	.013	.026	.036	.002	.001	.004	0	0	--
4/21	9.244	53.134	.109	1.787	1.544	33.088	.052	.221	.05	.079	.011	.022	.031	.001	.001	.003	0	0	--
4/22	9.264	53.287	.131	1.822	1.537	32.906	.048	.219	.035	.056	.011	.021	.028	.0004	.001	.003	0	0	--
4/23	9.363	53.169	.114	1.862	1.535	32.864	.048	.219	.045	.078	.01	.019	.026	0	.001	.004	0	0	2105
4/24	9.438	53.119	.14	1.902	1.547	32.803	.048	.221	.033	.059	.01	.02	.031	.001	.001	.004	0	0	2136
4/25	8.669	55.593	.114	2.017	1.419	31.074	.044	.208	.032	.055	.01	.019	.029	.001	.001	.005	0	0	2023
4/26	9.192	54.198	.084	2.053	1.45	31.972	.047	.207	.037	.067	.009	.018	.026	.0003	.001	.004	0	0	--
4/27	9.189	54.805	.093	2.036	1.547	31.223	.048	.137	.046	.082	.010	.019	.032	.001	.001	.005	0	0	1900
4/28	8.481	56.633	.096	2.274	1.403	29.958	.048	.209	.038	.059	.014	.026	.039	.002	.001	.005	0	0	1893
4/29	8.622	56.251	.167	2.175	1.460	30.232	.048	.217	.038	.064	.01	.02	.033	.001	.001	.005	0	0	1985
4/30	8.147	57.320	.078	2.473	1.283	29.606	.047	.191	.040	.062	.012	.025	.036	.002	.001	.005	.001	0	1917

TABLE XII (continued)
RETORT 6 OFFGAS ANALYSES

May 1979

te	H_2	N_2	O_2	CO	CH_4	CO_2	$C_2^=$	C_2	$C_3^=$	C_3	IC_4	BUT-I	NC_4	C T	IC_5	NC_5	C_6	C_7	H_2S
	% Volume																		PPM
'1	8.057	57.283	.094	2.589	1.286	29.584	.049	.192	.040	.064	.013	.026	.037	.002	.001	.005	0	0	1780
'2	7.938	57.422	.082	2.625	1.278	29.532	.049	.188	.043	.069	.010	.022	.030	.002	.001	.005	0	0	1808
'3	8.194	56.425	.090	2.684	1.312	30.166	.053	.192	.046	.072	.010	.021	.027	.003	.001	.004	0	0	1964
'4	7.816	56.496	.114	2.778	1.332	30.336	.049	.199	.045	.076	.010	.021	.028	.003	.001	.009	.0004	0	1787
'5	5.664	60.147	.109	3.430	.903	28.707	.043	.136	.034	.049	.006	.015	.015	0	.001	.005	0	.001	1387
'6	5.595	59.677	.041	3.430	.941	29.261	.048	.145	.038	.054	.006	.016	.015	.0004	.001	.005	.001	.0003	1404
'7	5.636	59.505	.044	3.415	.997	29.322	.053	.157	.044	.063	.006	.016	.016	0	.001	.005	.001	0	1495
'8	5.932	59.225	.039	3.417	1.011	29.307	.051	.164	.046	.065	.006	.018	.018	0	.001	.005	0	0	1563
'9	5.913	59.550	.05	3.344	1.009	29.047	.05	.167	.046	.066	.007	.019	.020	.001	.001	.005	0	0	1595
/10	5.902	59.711	.059	3.263	.995	28.983	.048	.165	.044	.066	.007	.019	.020	.001	.001	.005	0	0	1552
/11	5.883	59.584	.055	3.317	1.043	29.020	.049	.173	.046	.069	.007	.019	.022	.001	.001	.004	0	0	1472
/12	5.774	60.016	.036	3.195	1.066	28.805	.047	.180	.044	.071	.007	.019	.021	.002	.001	.006	0	0	1312
/13	5.740	59.562	.045	3.143	1.061	29.333	.048	.182	.045	.072	.008	.019	.022	.001	.001	.006	0	0	1325
/14	5.639	59.205	.039	3.136	1.100	29.743	.055	.191	.050	.076	.008	.021	.025	.003	.001	.006	0	0	1377
/15	5.642	59.474	.042	3.079	1.076	29.547	.052	.188	.048	.075	.009	.021	.028	.003	.001	.007	0	0	1391
/16	5.725	59.639	.052	3.013	1.120	29.284	.055	.198	.050	.078	.009	.023	.031	.003	.001	.007	0	0	1391
/17	5.806	60.195	.032	2.969	1.081	28.749	.053	.193	.051	.079	.009	.022	.029	.003	.001	.008	0	0	1410
/18	5.755	60.051	.027	3.022	1.052	28.941	.053	.189	.050	.077	.009	.022	.027	.002	.001	.008	0	.001	1419
/19	5.613	60.073	.031	3.102	1.032	29.084	.052	.187	.050	.077	.008	.021	.025	.003	.001	.008	0	.001	1352
/20	5.611	59.979	.024	2.917	1.036	29.286	.052	.188	.049	.082	.009	.021	.026	.003	.001	.008	.001	0	1345
/21	5.663	60.143	.025	2.950	1.015	29.046	.051	.184	.047	.076	.010	.023	.030	.003	.001	.009	.001	.001	1469
/22	5.800	59.163	.066	3.034	1.029	29.686	.048	.183	.047	.075	.011	.026	.037	.002	.001	.010	.002	.001	1580
/23	6.044	59.690	.036	3.011	.983	29.058	.043	.181	.044	.074	.007	.022	.036	.002	.001	.009	.002	.001	1568
/24	6.233	59.326	.052	2.654	1.013	29.230	.043	.189	.044	.077	.009	.023	.041	.002	.001	.007	.002	.001	1634
/25	6.272	59.481	.056	3.001	.996	29.057	.043	.187	.045	.077	.009	.022	.040	.003	.001	.009	.001	.001	-
/26	6.137	59.705	.036	3.018	.958	28.989	.042	.182	.043	.074	.009	.023	.040	.003	.001	.009	.002	.001	-
/27	6.187	59.489	.055	3.047	.975	29.092	.043	.184	.042	.071	.010	.023	.041	.003	.001	.009	.001	.001	-
/28	6.363	59.574	.050	3.030	.969	28.854	.043	.181	.041	.076	.010	.023	.041	.003	.001	.009	.002	.001	-
/29	6.075	59.718	.047	2.948	.973	29.097	.044	.183	.045	.075	.010	.024	.037	.003	.001	.009	.002	.001	1585
/30	5.559	61.2	.053	2.706	.981	28.347	.042	.182	.045	.076	.01	.023	.035	.003	.001	.01	.002	.001	1569
/31	5.280	61.611	.067	2.639	.970	28.275	.042	.181	.045	.075	.009	.023	.034	.003	.001	.008	.002	.001	1575

June 1979

	H_2	N_2	O_2	CO	CH_4	CO_2	$C_2^=$	C_2	$C_3^=$	C_3	IC_4	BUT-I	NC_4	C T	IC_5	NC_5	C_6	C_7	H_2S
	%Volume																		PPM
	5.800	60.942	.050	2.605	.989	28.442	.043	.186	.045	.078	.010	.024	.040	.003	.001	.005	.002	.001	1585
	5.961	60.961	.063	2.654	.95	28.230	.042	.182	.043	.075	.010	.023	.040	.002	.001	.005	.002	.001	1542
	5.887	60.955	.061	2.669	.951	28.247	.042	.181	.043	.075	.003	.019	.029	.001	.001	.006	.001	.001	--
	5.780	60.578	.082	2.659	.966	28.597	.041	.183	.042	.072	.008	.019	.029	.001	.001	.008	.001	.001	1476
	6.689	57.723	.06	2.767	1.162	30.418	.045	.216	.049	.089	.010	.022	.036	.002	.001	.007	.002	.004	1588
	5.991	61.111	.064	2.628	.995	28.065	.041	.186	.043	.076	.008	.018	.027	.001	.001	.008	.001	.001	1480
	5.747	61.503	.058	2.558	1.005	27.997	.041	.185	.044	.077	.008	.019	.030	.001	.001	.006	.001	.001	1551
	6.200	60.790	.069	2.534	1.019	28.223	.043	.186	.044	.076	.009	.019	.030	.001	.001	.005	.002	.001	1437
	6.399	59.994	.068	2.642	1.031	28.704	.045	.189	.045	.076	.009	.019	.029	.002	.001	.005	.002	.001	1375
)	6.111	60.462	.064	2.600	1.012	28.582	.047	.187	.046	.077	.009	.022	.035	.002	.001	.004	.002	.001	1422
1	5.733	60.274	.078	2.648	1.035	29.042	.050	.189	.048	.079	.010	.022	.040	.003	.001	.005	.002	.001	--
2	5.49	60.536	.054	2.612	1.035	29.11	.049	.19	.047	.08	.01	.022	.037	.003	.001	.005	.002	.001	1588
3	5.536	60.380	.060	2.656	1.033	29.012	.047	.191	.046	.080	.009	.021	.034	.003	.001	.005	.001	.001	1616
4	5.454	61.080	.063	2.574	.999	28.662	.045	.186	.044	.078	.010	.022	.037	.003	.001	.005	.002	.001	1724
5	5.565	60.555	.052	2.493	1.045	28.849	.046	.188	.045	.079	.010	.024	.041	.003	.001	.005	.002	.001	1851
6	5.425	61.873	.035	2.365	.973	28.182	.045	.181	.043	.075	.009	.020	.033	.003	.001	.005	.001	.001	1763
7	5.420	61.342	.050	2.381	.971	28.699	.043	.180	.043	.076	.009	.002	.032	.003	.001	.005	.001	.001	1689
8	5.767	60.827	.051	2.350	.972	28.905	.045	.179	.043	.075	.007	.018	.028	.002	.001	.004	.001	.001	1729
9	5.323	61.226	.035	2.321	.958	29.037	.043	.175	.042	.074	.008	.019	.025	.001	.001	.003	.001	.001	2039
0	5.449	61.293	.087	2.231	.959	28.856	.043	.176	.043	.075	.008	.019	.024	.002	.001	.003	0	0	1744
1	5.640	61.314	.060	2.213	.955	28.687	.045	.175	.043	.074	.008	.019	.024	.002	.001	.003	.001	0	1718
2	5.994	59.370	.055	2.287	1.062	30.083	.049	.192	.048	.080	.009	.021	.026	.002	.001	.004	.002	0	1714
3	6.090	60.013	.058	2.110	1.078	29.499	.048	.192	.046	.080	.009	.020	.026	.002	.001	.004	.001	0	1675
4	5.563	61.521	.064	2.140	.974	28.598	.046	.176	.044	.074	.008	.018	.023	.002	.001	.004	.001	0	1573
5	5.556	61.413	.067	2.220	.957	28.634	.046	.173	.044	.074	.008	.019	.022	.002	.001	.003	0	0	1591
6	5.576	61.145	.065	2.234	.963	28.816	.047	.174	.045	.073	.008	.019	.022	.002	.001	.004	-	-	1604
7	5.603	60.787	.075	2.333	.982	29.081	.047	.177	.044	.075	.009	.021	.025	.002	.001	.004	.001	0	1626
8	5.645	60.784	.072	2.359	.991	29.087	.046	.176	.044	.075	.011	.024	.030	.003	.001	.004	.001	.001	1630
9	5.721	60.758	.076	2.335	1.001	28.609	.053	.166	.044	.078	.011	.023	.030	.002	.002	.005	.001	.001	1643
0	5.517	61.308	.086	2.275	.974	28.449	.045	.167	.081	.075	.010	.022	.028	.002	.001	.005	.001	0	1538

TABLE XII (continued)
RETORT 6 OFFGAS ANALYSES

July 1979

Date	H_2	N_2	O_2	CO	CH_4	CO_2	$C_2^=$	C_2	$C_3^=$	C_3	IC_4	BUT-I	NC_4	C T	IC_5	NC_5	C_6	C_7	H_2S
									%Volume										PPM
7-1	5.515	61.367	.081	2.183	.984	28.789	.044	.177	.043	.075	.010	.023	.029	.002	.001	.005	.003	-0-	1526
7-2	5.552	61.367	.083	2.183	.992	28.633	.045	.177	.042	.073	.013	.028	.036	.004	.002	.005	.002	.001	1525
7-3	5.317	62.067	.096	2.310	.942	28.264	.045	.170	.042	.072	.012	.027	.033	.004	.001	.005	.001	.001	1510
7-4	5.407	61.518	.106	2.222	.949	28.641	.047	.171	.043	.072	.012	.027	.033	.004	.001	.005	.001	.001	1437
7-5	5.570	60.481	.095	2.282	1.008	29.326	.051	.181	.047	.076	.013	.031	.043	.004	.002	.005	.001	.001	1570
7-6	5.741	61.145	.099	2.179	1.014	28.596	.061	.182	.047	.083	.010	.024	.034	.004	.007	.023	.001	-0-	1532
7-7	4.685	61.467	.083	2.114	.982	29.539	.053	.158	.046	.073	.008	.018	.030	.003	.009	.030	.001	-0-	1478
7-8	4.732	61.954	.096	2.037	.963	29.089	.053	.156	.046	.072	.007	.017	.030	.003	.009	.029	.001	0	1466
7-9	4.893	61.496	.099	2.054	1.013	29.401	.054	.174	.047	.074	.008	.019	.026	.003	.004	.002	.001	0	1609
7-10	4.858	61.580	.111	2.093	.990	29.227	.055	.175	.046	.071	.008	.019	.022	.003	.001	.003	.003	0	1765
7-11	4.938	61.279	.019	2.128	1.006	29.399	.056	.179	.047	.021	.008	.019	.023	.003	.001	.003	.002	0	1775
7-12	5.054	60.799	.103	2.154	1.021	29.724	.058	.179	.048	.073	.008	.019	.024	.003	.001	.003	.003	0	1802
7-13	5.137	58.757	.074	2.230	1.056	31.627	.061	.174	.050	.074	.008	.018	.025	.003	.004	.013	.002	.001	1783
7-14	5.381	57.601	.058	2.226	1.133	32.487	.064	.176	.054	.080	.007	.017	.027	.004	.009	.028	.001	.001	2212
7-15	6.599	55.304	.131	1.082	.934	34.954	.059	.139	.038	.066	.006	.012	.026	.002	.008	.028	.001	0	2624
7-16	7.587	59.183	.307	.741	.797	30.359	.039	.139	.039	.055	.006	.017	.02	.002	.001	.003	.003	0	2739
7-17	8.868	56.650	.257	.768	.984	31.363	.043	.174	.043	.070	.008	.021	.028	.002	.001	.004	.003	0	2931
7-18	22.564	7.451	.080	1.364	3.451	62.231	.098	.596	.120	.244	.035	.067	.116	.011	.003	.010	.007	.003	3077
7-19	32.559	1.507	.078	1.300	3.320	59.833	.095	.576	.118	.239	.034	.065	.114	.012	.003	.010	.007	.003	
7-20	36.063	1.212	.097	1.278	3.383	56.748	.095	.585	.117	.242	.036	.065	.116	.013	.003	.01	.007	.003	3234
7-21	37.154	1.608	.094	1.251	3.379	55.278	.095	.584	.117	.241	.034	.062	.11	.012	.003	.01	.007	0	2896
7-22	37.296	2.938	.113	1.282	4.235	52.498	.105	.731	.133	.303	.043	.071	.133	.014	.004	.011	.007	.001	3090
7-23	37.51	3.123	.085	1.313	4.930	50.939	.111	.842	.140	.347	.053	.077	.153	.016	.004	.013	.009	.005	3070
7-24	36.242	3.077	.117	1.322	5.358	50.371	.111	.907	.140	.374	.052	.069	.147	.150	.004	.012	.009	.009	3071
7-25	40.517	1.873	.084	1.241	4.466	50.253	.095	.750	.118	.313	.045	.061	.130	.013	.003	.011	.009	.008	3090
7-26	40.862	1.353	.092	1.226	5.171	49.478	.104	.875	.131	.359	.056	.074	.160	.016	.004	.014	.011	.011	3037
7-27	39.428	.461	.205	1.401	6.716	49.428	.128	1.152	.161	.476	.074	.091	.205	.021	.005	.019	.013	.012	3075
7-28	42.911	.815	.099	1.148	3.590	50.196	.088	.575	.559	.240	.037	.050	.110	.011	.003	.013	.009	.009	2934
7-29	44.298	.691	.086	1.006	3.486	49.190	.096	.579	.093	.217	.036	.056	.111	.011	.003	.013	.009	.009	2974
7-30	42.064	.716	.097	.980	3.770	50.288	.105	.625	.107	.262	.039	.060	.119	.012	.003	.013	.010	.009	3297
7-31	43.463	.781	.099	.933	3.784	49.522	.109	.629	.110	.267	.039	.062	.122	.013	.003	.013	.009	.010	3345

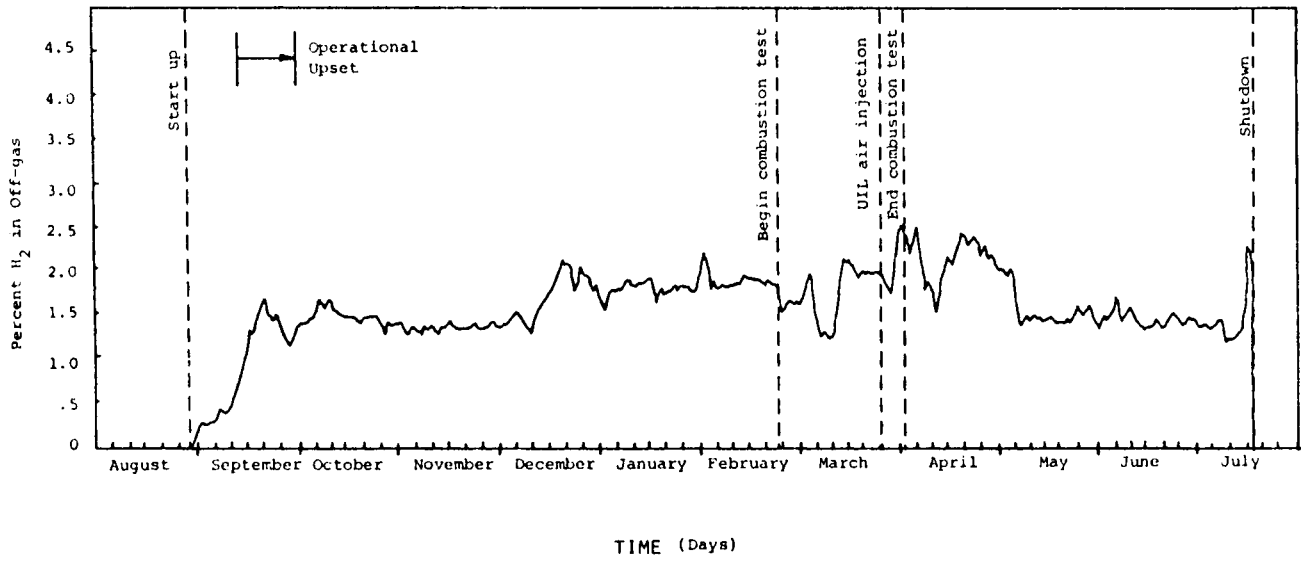


Figure 23. Percent hydrogen in Retort 6 offgas.

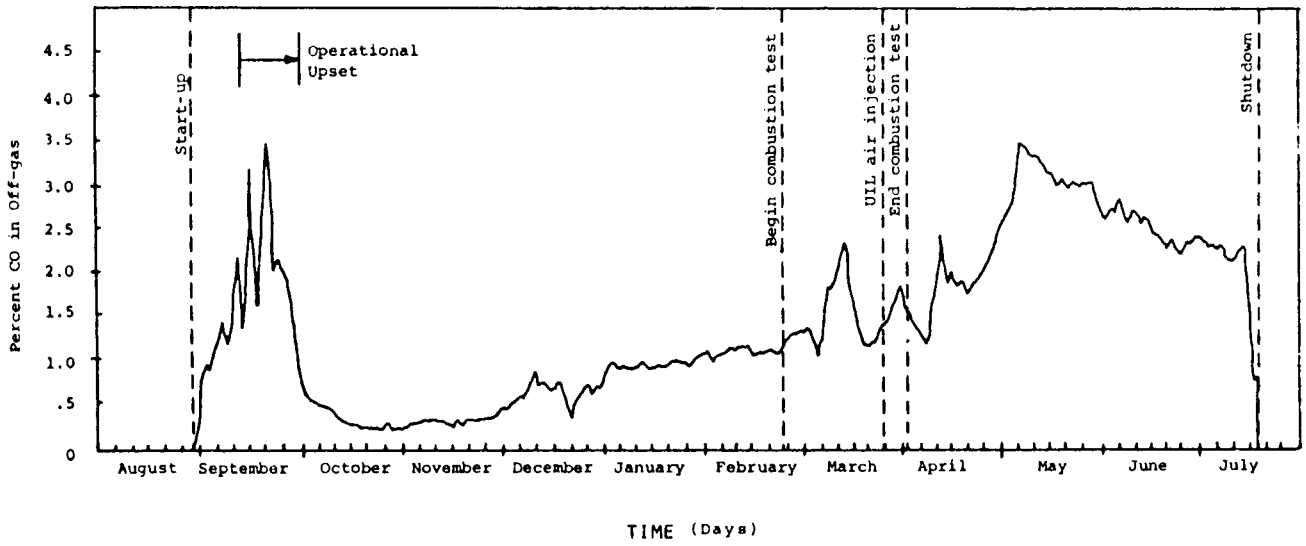


Figure 24. Percent carbon monoxide in Retort 6 offgas.

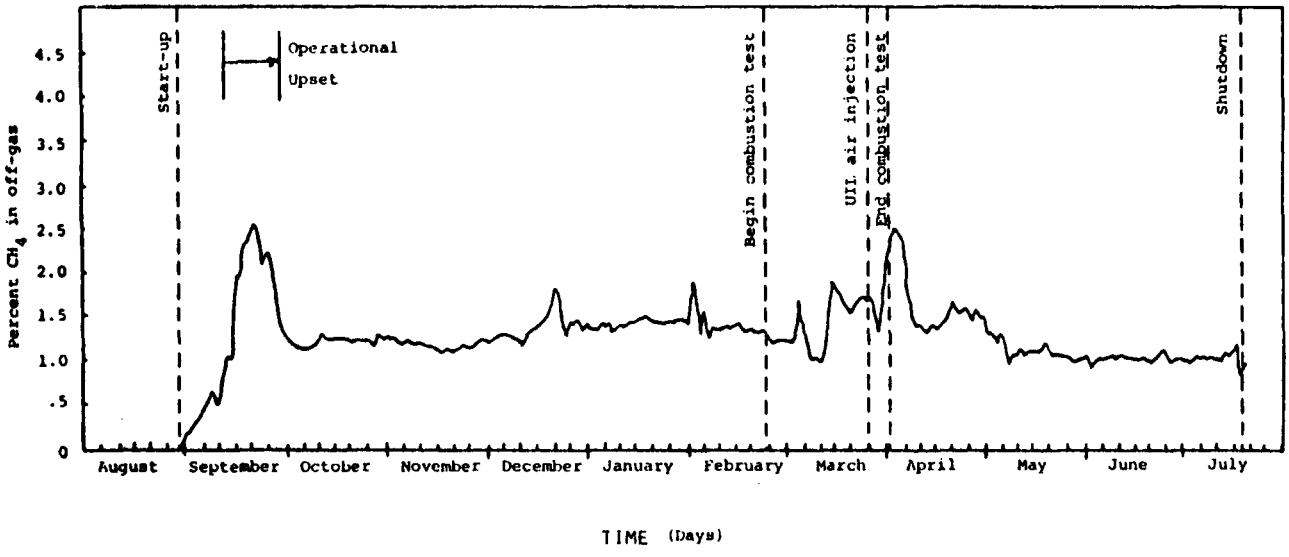


Figure 25. Percent methane in Retort 6 offgas.

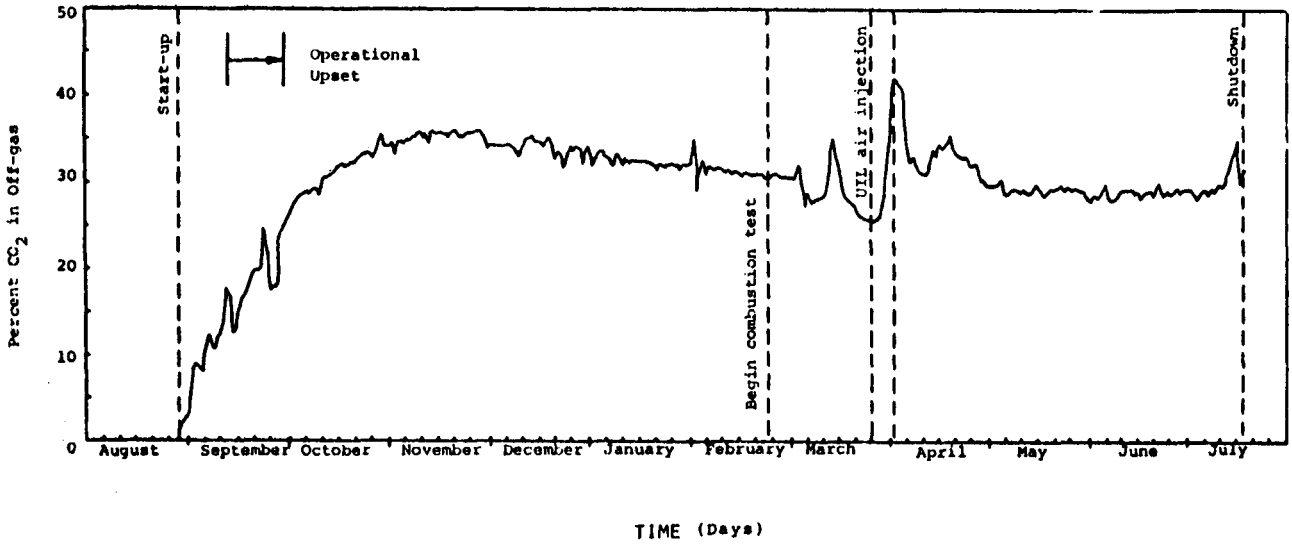


Figure 26. Percent carbon dioxide in Retort 6 offgas.

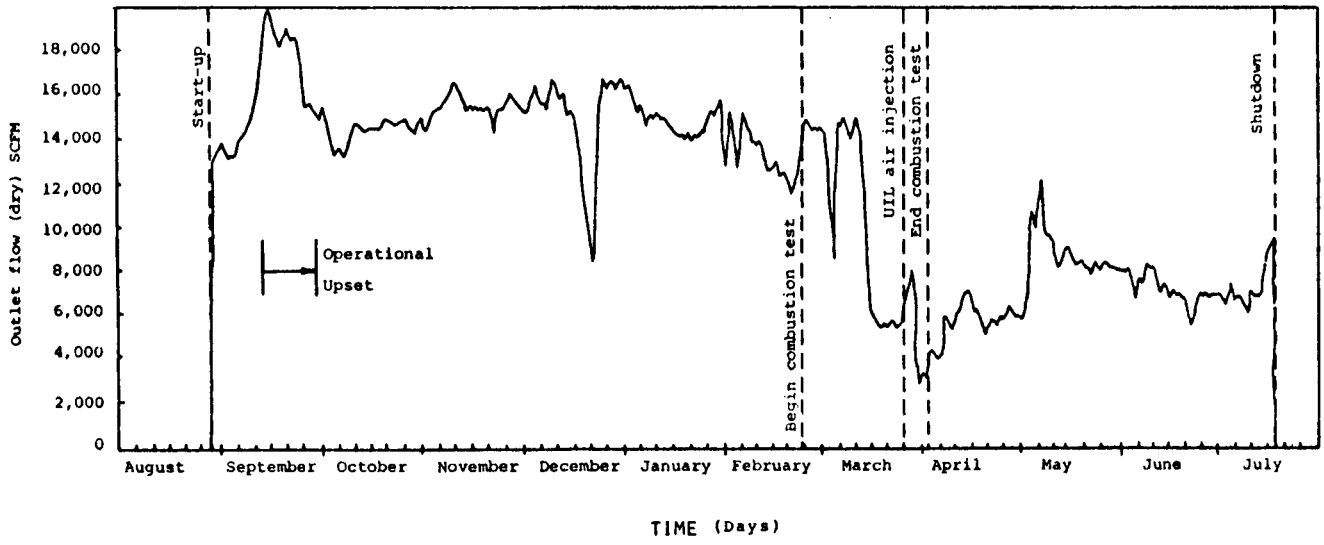


Figure 27. Retort 6 dry product gas.

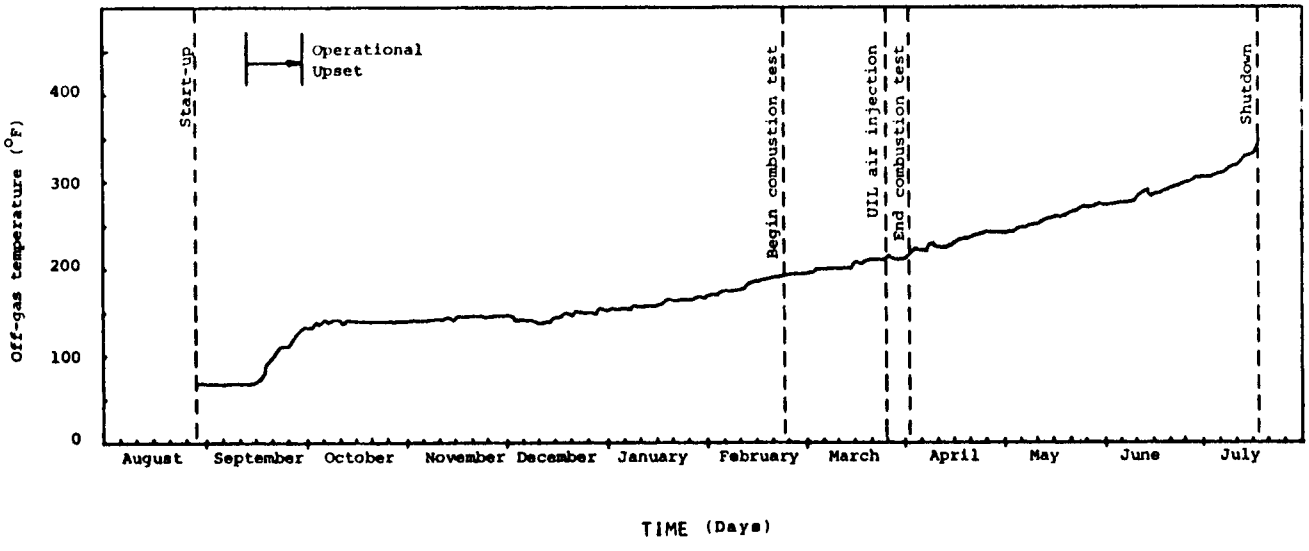


Figure 28. Retort 6 offgas temperature.

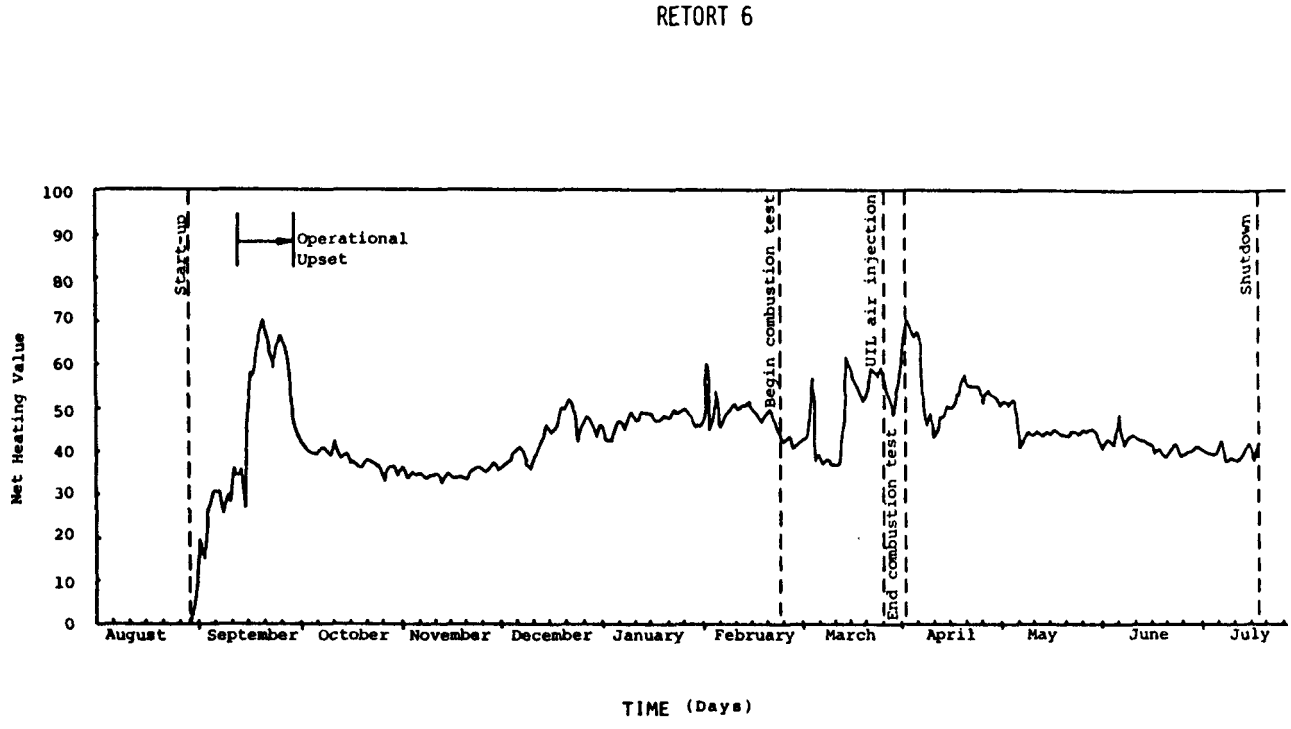


Figure 29. Retort 6 net heating value.

d. Process Water Analysis

Beginning August 24, 1978, four days before Retort 6 ignition, weekly water samples were taken from behind the Product Level bulkhead and analyzed. These analyses are listed in Table XIII. On two occasions, samples were not taken. One was because of the upset in conditions in September when the bulkhead was inaccessible, and the other was because the water level was too low for pumping the sample.

7. Retort 6 Pilot Offgas Treatment Program

The Retort 6 side stream pilot facility was made up of a contact condenser system and an electrostatic precipitator and sized to handle up to 15 per cent of the offgas. The contact condenser system consisted of a packed column, a hold-up tank for oil/water separation and a finned tube air cooler.

The pilot plant hold-up tank was charged with offgas condensate in late February 1979, and the condenser system was started-up on February 23. A series of 28 tests was then conducted ending on March 26. (The pilot plant was shutdown from March 1 to 15 to relocate the offgas blower from the gas inlet line to the gas outlet line in order to operate the condenser at lower pressures). The tests consisted of varying the packed column temperature, pressure, gas loading, and liquid-to-gas ratio.

The pilot plant was operated again from May 19 to June 10 to recover light oil and to provide experience for the process operators. The pilot plant was then modified to allow stripped feed-water operation. A series of 10 tests was conducted with the stripped feedwater system from June 19 to June 30.

The packing was then removed from the condenser column and replaced with sprays. A series of 14 tests was conducted with the spray tower system from July 3 through 11.

TABLE XIII
SUMMARY OF RETORT 6 PROCESS WATER ANALYSES

PARAMETER		ANALYSIS BY SAMPLE DATE									
		8/24/78	8/31/78	9/8/78	9/15/78	9/22/78	9/29/78	10/5/78	10/12/78	10/20/78	10/26
Total Alkalinity,	mg/l as $CaCO_3$	720	950	1460	Not sampled because of upset in Retort 6 conditions	2600	540	3500	Not sampled because water level was pumped down prior to sampling	1600	8600
Carbonate,	mg/l as $CaCO_3$	20	<1	<1		<1	<1	<1		300	500
Bicarbonate,	mg/l as $CaCO_3$	700	950	1460		2600	540	3500		1200	8100
Total Dissolved Solids,	mg/l	7000	6000	9400		13000	13000	18000		1300	2200
Total Suspended Solids,	mg/l	-	-	400		260	100	300		140	640
Sulfate,	mg/l	3700	3100	4200		4000	4000	4000		3400	3000
Chloride,	mg/l	300	400	100		230	240	85		64	80
Fluoride,	mg/l	11.8	12	10		8.3	15	14		21	24
Phenol,	mg/l	0.68	0.11	0.12		0.35	8.7	3.7		7.2	18
Nitrate,	mg/l	140	170	380		75	62	150		490	710
Oil & Grease	mg/l	20	20	20		10	30	20		150	150
Silica,	mg/l	17	14	9.2		13	16	22		24	23
Sodium,	mg/l	1700	2000	2400		3600	3700	3700		4000	4200
Potassium,	mg/l	23	13	15		43	61	54		67	80
Arsenic,	mg/l	<0.02	<0.02	0.15		<0.02	0.07	0.05		0.17	0.2
Iron,	mg/l	<0.5	<0.5	150		2	2	2		<0.5	<0.5
Magnesium,	mg/l	40	37	64		230	140	140		67	44
Manganese,	mg/l	<0.2	<0.2	0.7		0.10	0.05	0.04		<0.02	<0.0
Calcium,	mg/l	65	79	90		330	150	120		29	8.7
Boron,	mg/l	13	<0.04	30		0.22	<0.04	16		3.9	9.4
Vanadium,	mg/l	<0.1	<0.1	<0.1		<0.1	<0.1	0.1		<0.1	<0.1
Copper,	mg/l	0.1	<0.02	<0.02		0.2	<0.02	<0.02		<0.02	<0.0
Molybdenum,	mg/l	6	6	10		20	10	2		0.1	0.6
Lithium,	mg/l	2	2	2		4	3	3		2	2
Zinc,	mg/l	0.03	0.03	0.03		5	0.1	0.02		<0.02	<0.0
Aluminum,	mg/l	0.4	0.3	0.4		0.2	0.1	0.4		0.2	0.0
Barium,	mg/l	<0.5	<0.5	0.7		0.7	0.8	2		<0.5	0.7
Strontium,	mg/l	5	6	8		21	20	20		7	4
Lead,	mg/l	0.1	0.05	<0.05		0.1	<0.02	<0.02		0.1	0.1
Nickel,	mg/l	<0.02	<0.02	0.04		0.3	0.1	0.03		0.02	0.0
Cadmium,	mg/l	<0.02	<0.02	<0.02		<0.02	<0.02	<0.02		<0.02	<0.0
Ammonia, as N,	mg/l	-	28	7.7		-	3.1	-		200	850
Sulfite,	mg/l	-	-	-		-	-	-		-	-

TABLE XIII (continued)
SUMMARY OF RETORT 6 PROCESS WATER ANALYSES

PARAMETER		ANALYSIS BY SAMPLE DATE									
		11/2/78	11/10/78	11/16/78	11/21/78	11/30/78	12/7/78	12/13/78	12/21/78	12/29/78	1/4/79
otal Alkalinity,	mg/l as $CaCO_3$	10,200	11,000	11,500	12,600	11,800	10,900	11,200	12,500	13,800	14,700
arbonate,	mg/l as $CaCO_3$	1,000	1,200	1,600	2,800	2,400	2,100	1,600	1,900	2,800	2,400
icarbonate,	mg/l as $CaCO_3$	9,200	9,800	9,900	9,800	9,400	8,800	9,600	9,600	11,000	13,000
otal Dissolved Solids,	mg/l	13,000	2,500	2,500	12,000	12,000	12,300	12,000	12,200	12,600	14,000
otal Suspended Solids,	mg/l	9 900	350	350	160	280	280	140	300	300	210
ulfate,	mg/l	2,500	2,000	1,700	1,600	1,200	1,300	600	730	750	720
hloride,	mg/l	66	71	180	110	58	39	96	180	250	110
luoride,	mg/l	27	29	30	34	34	37	37	32	41	36
henol,	mg/l	20	27	20	44	24	56	39	26	7.3	19
itrate,	mg/l	640	330	390	390	540	640	450	590	540	600
il & Grease	mg/l	300	200	300	200	240	230	410	400	100	400
ilica,	mg/l	26	27	26	26	28	28	28	28	36	36
odium,	mg/l	4,000	4,400	4,400	4,400	4,400	4,400	4,100	4,100	4,400	4,300
otassium,	mg/l	81	88	88	92	97	97	85	87	88	86
rsenic,	mg/l	0.23	0.23	0.25	0.23	0.38	5.2	0.22	0.21	0.23	1.9
ron,	mg/l	<0.5	< 0.5	2	<0.5	<0.5	<0.5	0.5	<0.5	0.7	<0.5
lagnesium,	mg/l	29	20	13	9.6	6	6	4	3	3	3
langanese,	mg/l	<0.02	0.02	<0.02	<0.02	<0.02	0.03	<0.02	<0.02	<0.02	< 0.02
alcium,	mg/l	70	4.2	2.7	2.7	4	3	4	4	7.6	5
oron,	mg/l	3.7	12	11	8.5	15	17	15	12	14	15
anadium,	mg/l	<0.1	0.1	<0.1	<0.1	< 0.1	0.1	0.2	0.3	<0.1	<0.1
opper,	mg/l	0.04	<0.02	<0.02	<0.02	< 0.02	<0.02	<0.02	<0.02	< 0.02	<0.02
olybdenum,	mg/l	0.4	0.2	0.1	0.2	0.07	0.07	0.04	0.09	<0.02	0.02
ithium,	mg/l	2	2	2	2	2	2	2	2	2	2
inc,	mg/l	<0.02	<0.02	<0.02	< 0.02	0.03	<0.02	<0.02	0.02	0.03	< 0.02
luminum,	mg/l	<0.02	0.07	0.07	< 0.02	0.2	0.04	1	0.4	0.6	0.2
arium,	mg/l	2	2	2	2	3.3	3	4	3	2	2
trontium,	mg/l	4	3	2	2	2	2	2	2	2	2
ead,	mg/l	<0.02	<0.02	<0.02	< 0.02	<0.02	< 0.02	<0.02	<0.02	0.03	<0.02
ickel	mg/l	<0.02	0.04	0.02	<0.02	<0.02	< 0.02	<0.02	<0.02	<0.02	<0.02
admium,	mg/l	<0.02	<0.02	<0.02	<0.02	<0.02	< 0.02	<0.02	<0.02	<0.02	<0.02
mmonia, as N,	mg/l	2,000	1,300	1,800	1,800	1,600	1,500	1,800	2,600	1,500	1,700
ulfite,	mg/l	--	--	--	--	90	90	80	120	100	170

TABLE XIII (continued)
SUMMARY OF RETORT 6 PROCESS WATER ANALYSES

PARAMETER		ANALYSIS BY SAMPLE DATE									
		1/11/79	1/19/79	1/25/79	2/1/79	2/9/79	2/15/79	2/22/79	3/1/79	3/7/79	3/16/79
Total Alkalinity,	mg/l as $CaCO_3$	13,000	10,700	10,600	9,600	8,700	8,000	5,800	9,000	8,900	9,800
Carbonate,	mg/l as $CaCO_3$	2,200	2,100	2,600	1,600	1,600	1,500	840	1,700	2,300	2,800
Bicarbonate,	mg/l as $CaCO_3$	10,800	8,600	8,000	8,000	7,100	6,500	4,960	7,300	6,600	7,000
Total Dissolved Solids,	mg/l	12,000	11,400	11,600	11,400	11,000	11,200	11,000	11,000	12,000	10,000
Total Suspended Solids,	mg/l	250	600	100	340	120	170	200	270	120	140
Sulfate,	mg/l	670	730	740	770	820	970	110	1,000	1,000	890
Chloride,	mg/l	68	69	67	170	220	110	20	140	640	810
Fluoride,	mg/l	36	35	150	270	32	33	26	57	33	26
Phenol,	mg/l	33	19	24	20	31	48	21	38	36	53
Nitrate,	mg/l	930	1,200	680	520	320	460	220	320	240	230
Oil & Grease	mg/l	20	100	50	20	300	280	80	190	100	100
Silica,	mg/l	33	38	38	38	39	39	10	38	36	29
Sodium,	mg/l	4,000	3,400	3,600	3,500	3,100	3,400	82	3,100	3,000	3,900
Potassium,	mg/l	78	73	68	67	57	59	3	48	47	4
Arsenic,	mg/l	0.81	1.6	3.2	0.80	0.84	0.44	0.07	0.52	0.42	0.3
Iron,	mg/l	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	0.6	<0.5	<0.5
Magnesium,	mg/l	2	2	2	5	3	3	8	2	3	2
Manganese,	mg/l	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.0
Calcium,	mg/l	3	4	6	6	7	5	16	7	6	7
Boron,	mg/l	14	14	12	12	12	5	2	<0.04	0.04	5.1
Vanadium,	mg/l	<0.1	0.3	<0.1	<0.1	<0.1	<0.1	<0.1	<0.1	0.1	<0.1
Copper,	mg/l	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.0
Molybdenum,	mg/l	0.1	0.3	0.1	0.1	0.03	0.06	<0.02	0.1	0.1	0.4
Lithium,	mg/l	2	2	2	2	2	2	0.04	1	1	0.9
Zinc,	mg/l	0.02	0.03	0.05	0.03	0.06	0.02	0.02	<0.02	<0.02	<0.0
Aluminum,	mg/l	<0.1	0.4	0.3	0.2	0.2	<0.1	0.1	0.3	0.3	0.3
Barium,	mg/l	2	2	2	2	2	2	0.5	2	1	4
Strontium,	mg/l	2	2	2	2	2	2	2	0.8	0.8	0.8
Lead,	mg/l	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.0
Nickel	mg/l	<0.02	<0.02	0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.0
Cadmium,	mg/l	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.0
Ammonia, as N,	mg/l	1,600	1,400	1,200	1,400	750	1,000	1,800	970	1,100	1,600
Sulfite,	mg/l	330	380	240	300	170	180	50	60	90	50

TABLE XIII (continued)
SUMMARY OF RETORT 6 PROCESS WATER ANALYSES

PARAMETER		ANALYSIS BY SAMPLE DATE					
		3/22/79	3/29/79	4/11/79	4/20/79	4/26/79	5/3/79
Total Alkalinity,	mg/l as $CaCO_3$	7,900	7,700	8,300	6,700	6,700	7,000
Carbonate,	mg/l as $CaCO_3$	2,700	2,100	2,200	1,700	1,600	2,000
Bicarbonate,	mg/l as $CaCO_3$	5,200	5,600	6,100	5,000	5,100	5,000
Total Dissolved Solids,	mg/l	9,400	9,800	11,000	10,000	9,600	9,600
Total Suspended Solids,	mg/l	310	330	120	80	180	200
Sulfate,	mg/l	1,100	1,100	1,800	1,600	1,600	1,600
Chloride,	mg/l	420	130	130	62	120	31
Fluoride,	mg/l	33	32	36	40	42	46
Phenol,	mg/l	70	31	30	29	31	18.5
Nitrate,	mg/l	180	280	410	530	290	580
Oil & Grease	mg/l	70	30	60	40	40	33
Silica,	mg/l	32	31	38	39	37	35
Sodium,	mg/l	2,800	2,900	3,400	3,100	3,000	3,200
Potassium,	mg/l	53	47	66	60	54	56
Arsenic,	mg/l	0.27	0.20	0.16	0.1	0.06	0.07
Iron,	mg/l	<0.5	0.5	4	<0.5	<0.5	<0.5
Magnesium,	mg/l	2	2	5	3	2	2
Manganese,	mg/l	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02
Calcium,	mg/l	7	6	12	6	9	47
Boron,	mg/l	5.9	6.0	7.0	9.2	9.2	6
Vanadium,	mg/l	0.1	<0.1	<0.1	0.1	<0.1	<0.1
Copper,	mg/l	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02
Molybdenum,	mg/l	0.2	0.3	0.2	0.4	0.1	0.1
Lithium,	mg/l	1	1	1	0.9	0.9	0.9
Zinc,	mg/l	<0.02	<0.02	0.1	<0.02	<0.02	<0.02
Aluminum,	mg/l	0.32	0.4	0.2	<0.1	0.2	0.1
Barium,	mg/l	3	3	2	0.7	<0.5	<0.5
Strontium,	mg/l	0.7	0.8	1	0.9	0.9	0.8
Lead,	mg/l	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02
Nickel	mg/l	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02
Cadmium,	mg/l	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02
Ammonia, as N,	mg/l	1,300	1,300	1,100	890	780	860
Sulfite,	mg/l	100	60	160	120	140	140

TABLE XIII (continued)
SUMMARY OF RETORT 6 PROCESS WATER ANALYSES

BY COORS LABORATORY

	8/24/78	8/31/78	9/8/78	9/22/78	9/29/78	10/5/78	10/20/78	10/24/78	11/2/78	11/10/78
TOC (mg/l)	34	30	204	886	1110	949	1235	878	1255	1800
DOC (mg/l)	29	26	188	817	986	496	1073	943	1851	1394
S_2O_3 (mg/l)	28	30	38	628	748	107	111	197	126	187
Nitrogen Kjeldahl (mg/l)	28.7	30.6	39.9	270	451	588	2.8	812	633	1340
Fecal Coliform (colonies/100 ml)	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1
Total Alpha (pCi/l)	72±8.9	0 ± 8.0				48 ± 18	24 ± 13	33 ± 15	18 ±11	
Total Beta (pCi/l)	170±40	0 ± 25				0 ± 16	0 ± 13	32 ± 15	0 ± 8	
Radium 226 (pCi/l)	5.5±1.9					0.4±1.4		0.2±0.08	0.65±0.18	
Silver (mg/l)										
Selenium (mg/l)	<0.02	<0.02	0.04	0.03	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02
Mercury (mg/l)	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02

TABLE XIII (continued)
SUMMARY OF RETORT 6 PROCESS WATER ANALYSES

BY COORS LABORATORY

	11/16/78	11/21/78	11/30/78	12/4/78	12/7/78	12/11/78	12/13/78	12/29/78	1/4/79	1/11/79	1/19/79
TOC (mg/l)	940	1767	7685	39	2149	1855	1741	1886	1971	2600	1910
DOC (mg/l)	838	1654	2561	21	1498	1380	1231	1761	1819	2250	1510
S_2O_3 (mg/l)	214	56	106	38	196	170	620	211	992	398	560
Nitrogen-Kjeldahl (mg/l)	114	8	10	39.9	1080	1830	29	846	545	1140	1320
Fecal Coliform (colonies/100 ml)	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1
Total Alpha (pCi/l)		16	11		14	11	14	4.3	14	72	58
Total Beta (pCi/l)		65	17		9	0	22	3	4	1	23
Radium 226 (pCi/l)		1.5					1.3			0.91	3.3
Silver (mg/l)										<0.01	<0.01
Selenium (mg/l)	<0.02	<0.02	<0.02	0.04	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02
Mercury (mg/l)	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02

TABLE XIII (continued)
SUMMARY OF RETORT 6 PROCESS WATER ANALYSES

BY COORS LABORATORY

	1/25/79	2/1/79	3/22/79	3/29/79	4/11/79	4/20/79	4/26/79	5/3/79	5/10/79	5/18/79	6/8/79
TOC (mg/l)	3780	3510	3400	3580	321	360	509	513	403	490	110
DOC (mg/l)	3490	2910	2800	3010	308	350	368	491	312	437	50
S_2O_3 (mg/l)	269	150	35	43	107	91	70	57	50	97	183
Nitrogen-Kjeldahl (mg/l)	822	923	800	1050	1110	1010	216	94	49	1250	2190
Fecal Coliform (colonies/100 ml)	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1	<1
Total Alpha (pCi/l)	48	23	11	26							
Total Beta (pCi/l)	29	45	7	134							
Radium 226 (pCi/l)	0.8	0.5		1.0							
Silver (mg/l)	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
Selenium (mg/l)	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	0.04
Mercury (mg.l)	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02	<0.02

Early evaluation of the data showed an oil loss in the range of 10-40 per cent of the oil contained in the slip stream offgas through the plant.

8. Mine Stability

The program for mine design and stability with the U.S. Bureau of Mines began in 1977. The three major program elements identified as important items directly relating to the safety of mining personnel and the development and design of economic mining methods in oil shale were:

- evaluation of loading conditions relevant to the retort,
- evaluation of subsidence potential, and
- determination of criteria for establishing a mining level.

To accomplish the program, a number of tests and monitoring activities were performed. Before the rubbling of Retort 6, strain relief overcoring was done to determine wall stress and the relieved core stress; spent shale tests were run to develop compaction vs. load properties; physical property tests were run for pillar and rock strength and compared with assays taken from core samples.

Analysis of the preliminary data from strain relief overcoring in the Retort 6 Air Level pillars before and after rubbling indicated:

- a decrease in stress from ~1400 psi to 200 psi;
- the sill pillar was supporting an overlying rock load at 200 psi and the weight of the pillar itself only produces a 10-15 psi load; and
- the sill pillar carried some overburden load.

Spent shale test results indicated that spent shale can support a load of 1200 psi applied uniaxially. The shale will compress about 2% before failure if the sample is not confined. Dynamic properties were investigated. The samples for these tests were taken from the top of Retort 1E, which was retorted in the Summer of 1973.

USBM and Woodward-Clyde instruments for stress and temperature were being monitored to record the effects of retorting on the rock surrounding Retort 6 and the change in stress in the rubble pile, respectively. The data through mid-March 1978 indicated that a 60 psi (+ 5 psi)/°F temperature change is reasonable for oil shale grades ranging from 10 to 50 gpt in the temperature range up to 167°F. Stress changes in the 167°F to 232°F temperature range vary somewhat with grade and are much greater.

F. BLAST-INDUCED PERMEABILITY AROUND RETORTS

One of the main objectives of partial Retort 8X is to determine the permeability in a 50-foot inter-retort pillar between closely spaced retorts. The 50-foot pillars are not designed to carry overburden load, but to isolate retorts from one another from a flow point of view. The purpose of this blast-induced permeability project is to assess blast fracturing around full scale retorts on their open sides and between closely spaced retorts.

The blast damage to date has been assessed in two ways: by *in situ* cross-hole acoustic measurements and laboratory strength, porosity, permeability and acoustic measurements performed by the U.S. Bureau of Mines and by *in situ* cross-hole and single-hole permeability measurements performed by Systems, Science and Software (S^3) for OOSI. These methods were used before the blasting to obtain natural *in situ* conditions and after blasting to determine the actual fracturing of the rock mass due to the blast. Only the results from S^3 are available at this time but these are the most

valid tests performed to determine the actual in situ permeability. Measurements were taken on the open north side of Retort 8 (top of page) and between Retorts 8 and 8X, as shown in the layout of Retort 7, 8 and 8X in Figure 30. Additionally, bulk flow and tracer test methods will be used to evaluate pillar and connecting drift permeability later in the R7 and 8 program.

The results of the flow tests on the north side of R8 are given in Figure 31 where the retort boundary is close to the 65.2-foot hole depth. This shows that all the blast damage on an open side of a retort is confined very close to the boundary, some two to three feet. Figure 32 shows the results of the flow tests between R8 and 8X where the hole is directed toward R8X from the drift between R8 and 8X. The permeability along this entire hole was above one darcy which is about 20 times the permeability in the damaged region on the north open side of R8. The most damaged region between R8 and 8X occurred about 20 feet from the R8X boundary where the permeability was about 90 darcies. It is not known whether a core of solid rock exists in this 50-foot pillar and how far the enhanced 90 darcy type damage extends since the angle of the hole used would not allow this to be determined. An additional hole may be cored as shown in Figure 33 and flow tested to better describe the damage between R8 and 8X.

A summary of the results including the calculated permeability in the retort rubble is given in Table XIV. The permeability in 20% void fraction rubble is 10,000 times higher than the most damaged region in the 50-foot pillar between R8 and 8X and this most damaged region is at least 20 feet from the rubble boundary. Flow will therefore prefer to stay in the rubble rather than to cross to another retort. A classification of various values of permeability is given in Figure 34 for intact and fractured rock. A view of the damage present around R7, 8 and 8X is given in Figure 35 in plan view and around R8 and 8X in Figure 36 in section view.

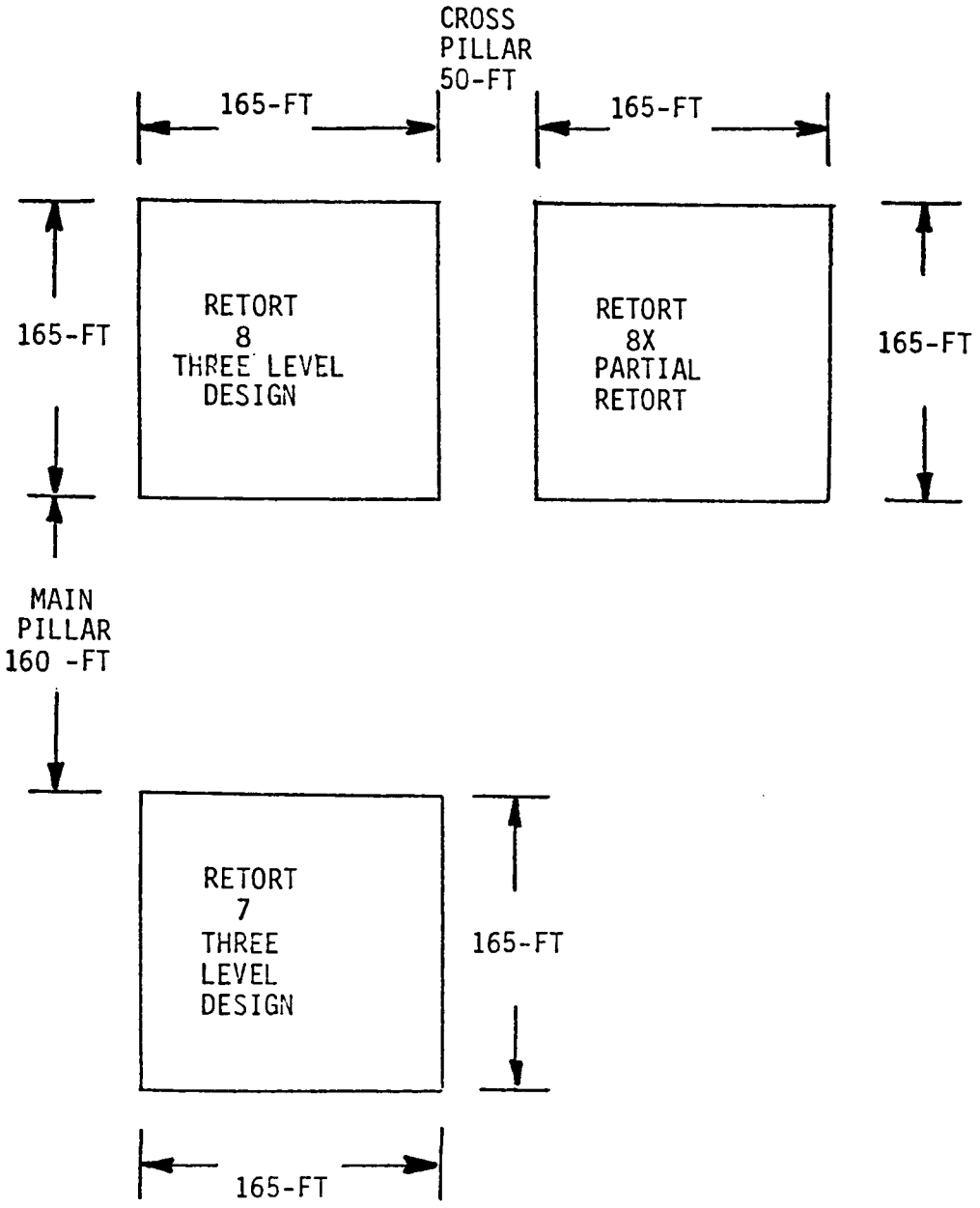


Figure 30. Retorts, 7, 8, and 8X plan view.

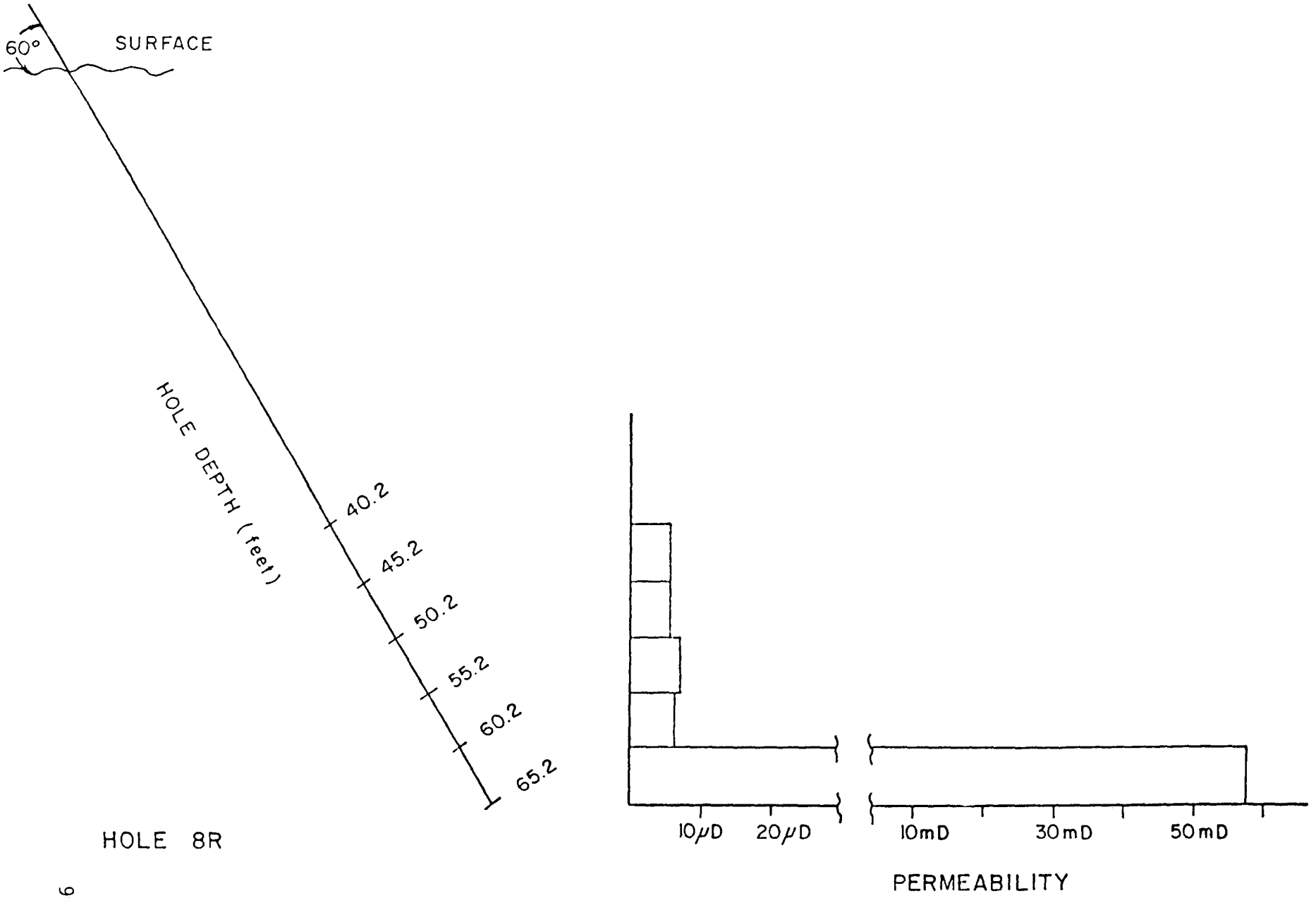


Figure 31. Results of flow tests on the north side of Retort 8.

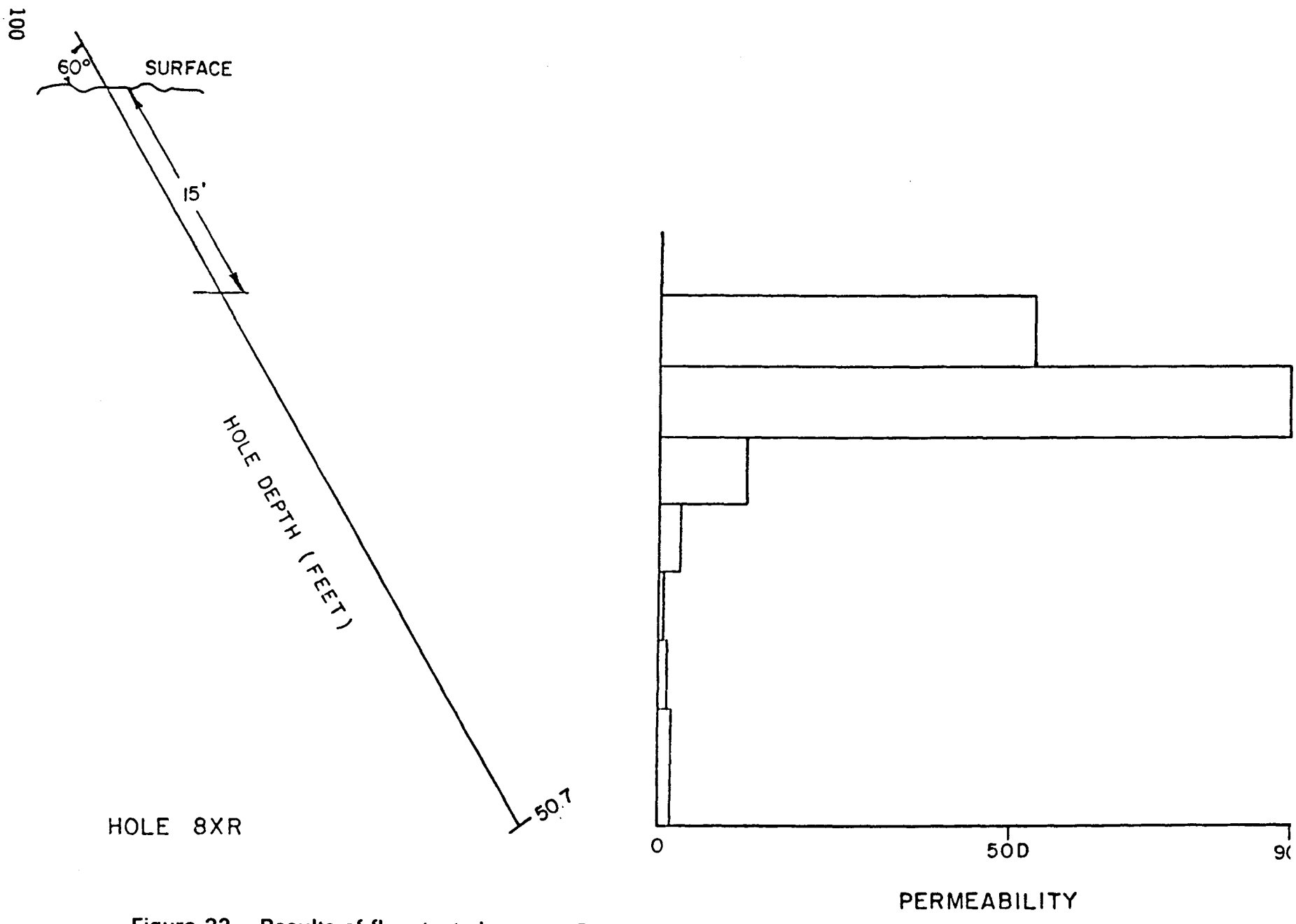


Figure 32. Results of flow tests between Retorts 8 and 8X.

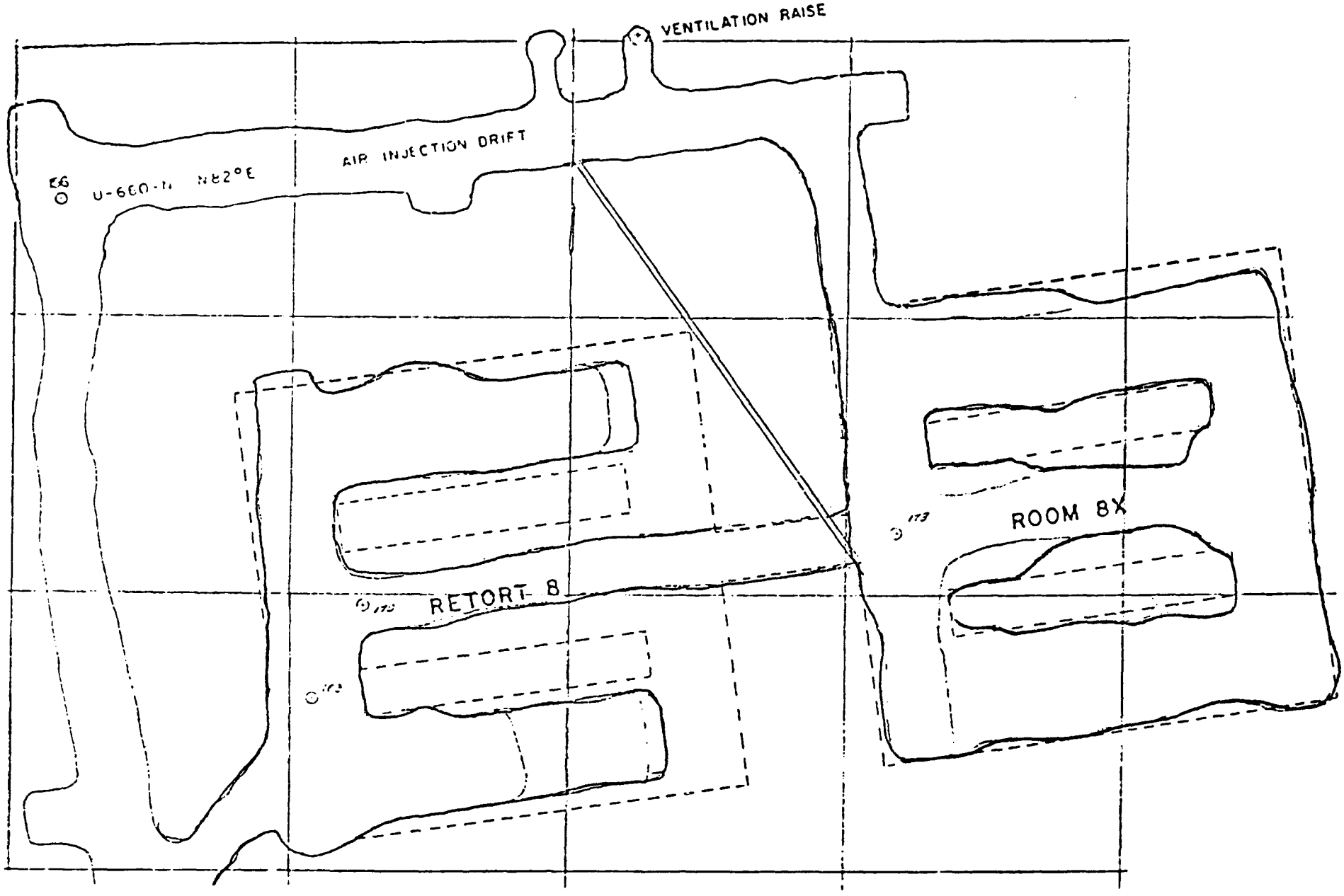


Figure 33. View of possible additional hole to be cored and flow tested between Retorts 8 and 8X.

TABLE XIV
RESULTS FROM IN SITU PERMEABILITY MEASUREMENTS

OPEN SIDE	• Permeability of 20μ D or less at depths 40-60 ft. • Permeability of up to 60 mD at 60-65 ft. depths near Retort 8 boundary
BETWEEN CLOSE RETORTS	• Permeability of at least 1 D over entire 15-50 ft. depth • Highest permeability up to 90 D not at Retort 8X boundary but at 15-25 ft. depth
RETORT RUBBLE	• Kozeny-Carmen equation predicts 1.4 x 10^6 D for VF = 0.20 and 5-in. particle size

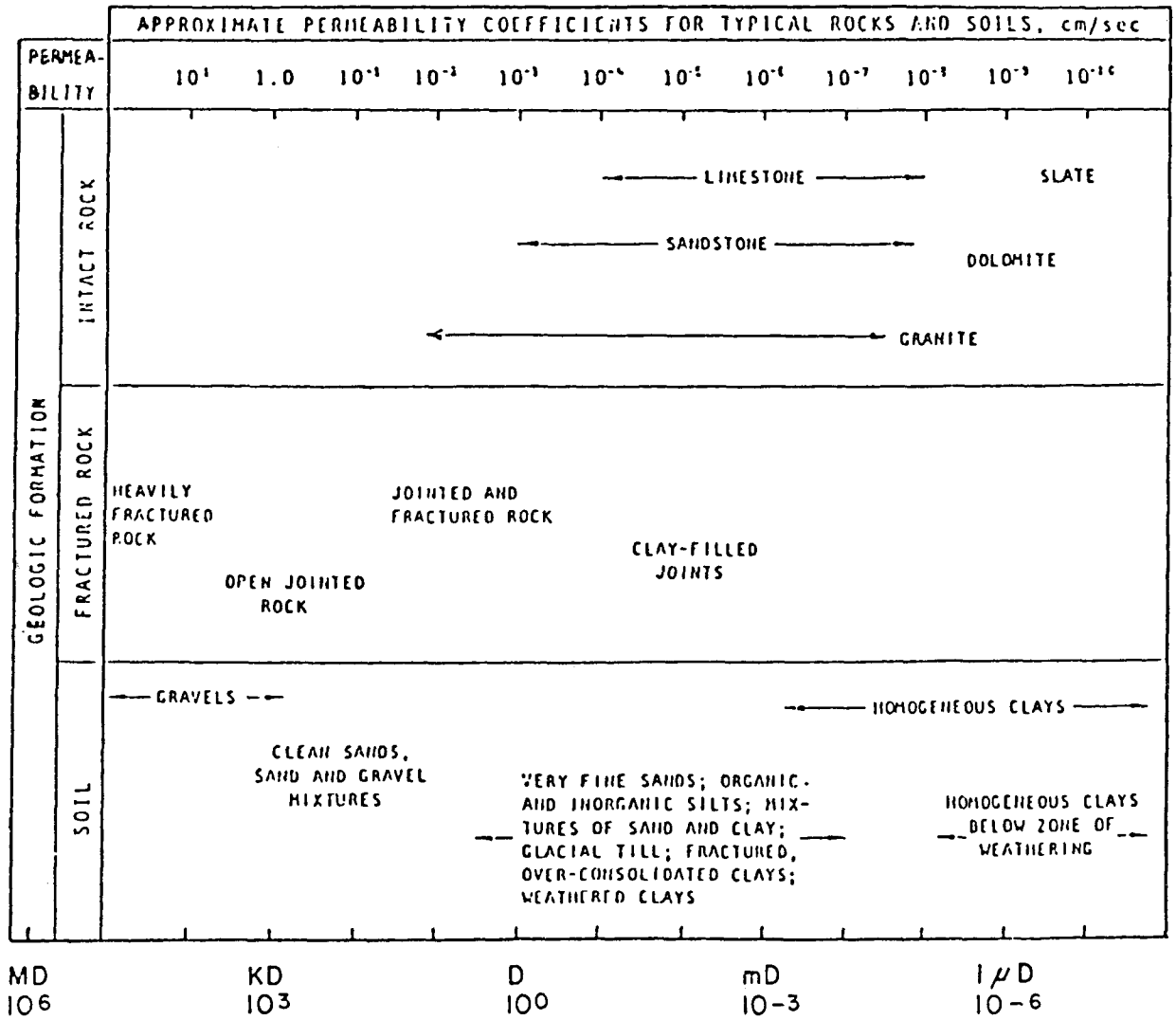


Figure 34. Classification of various values of permeability for intact and fractured rock.

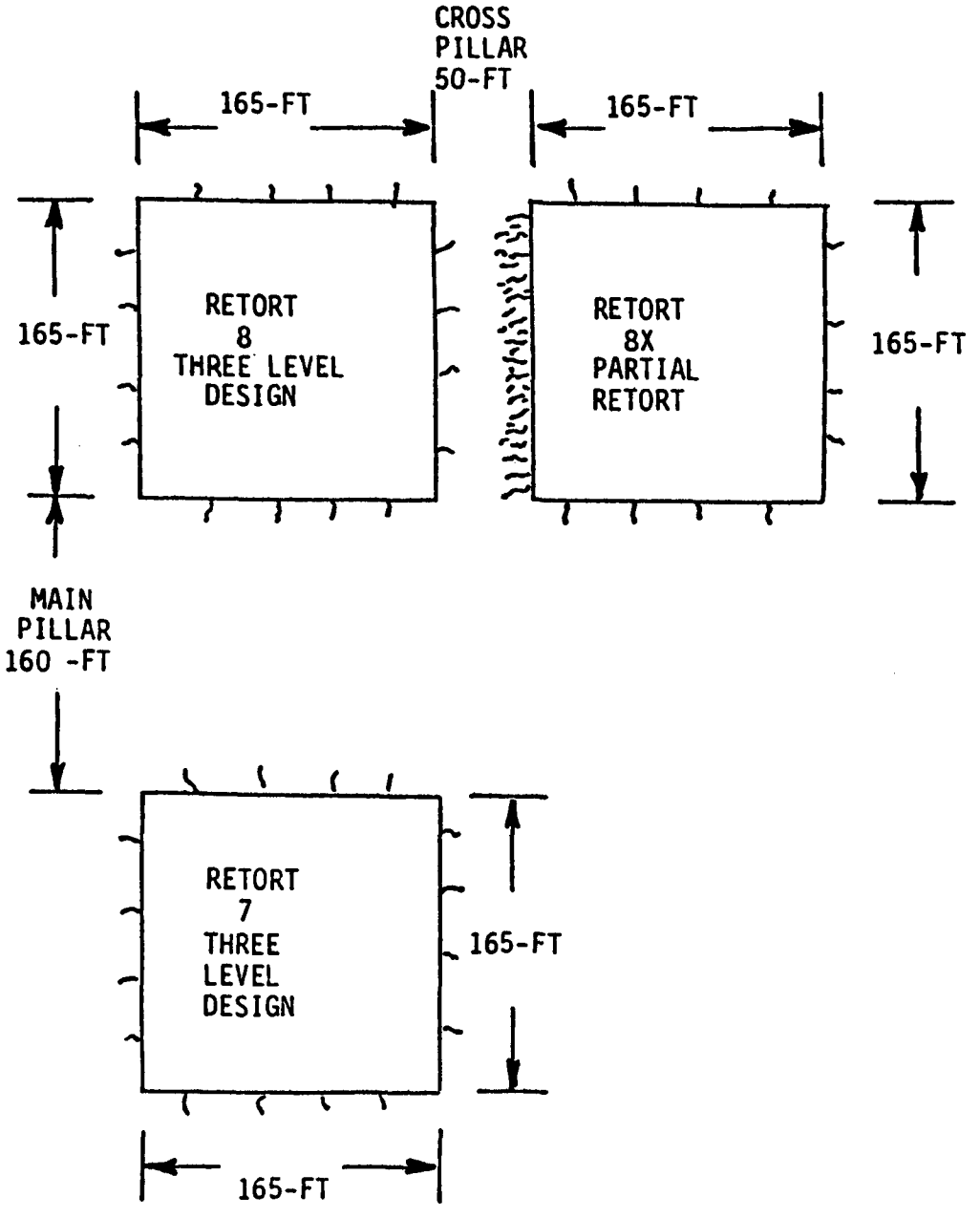


Figure 35. Damage present around Retorts 7, 8, and 8X, plan view.

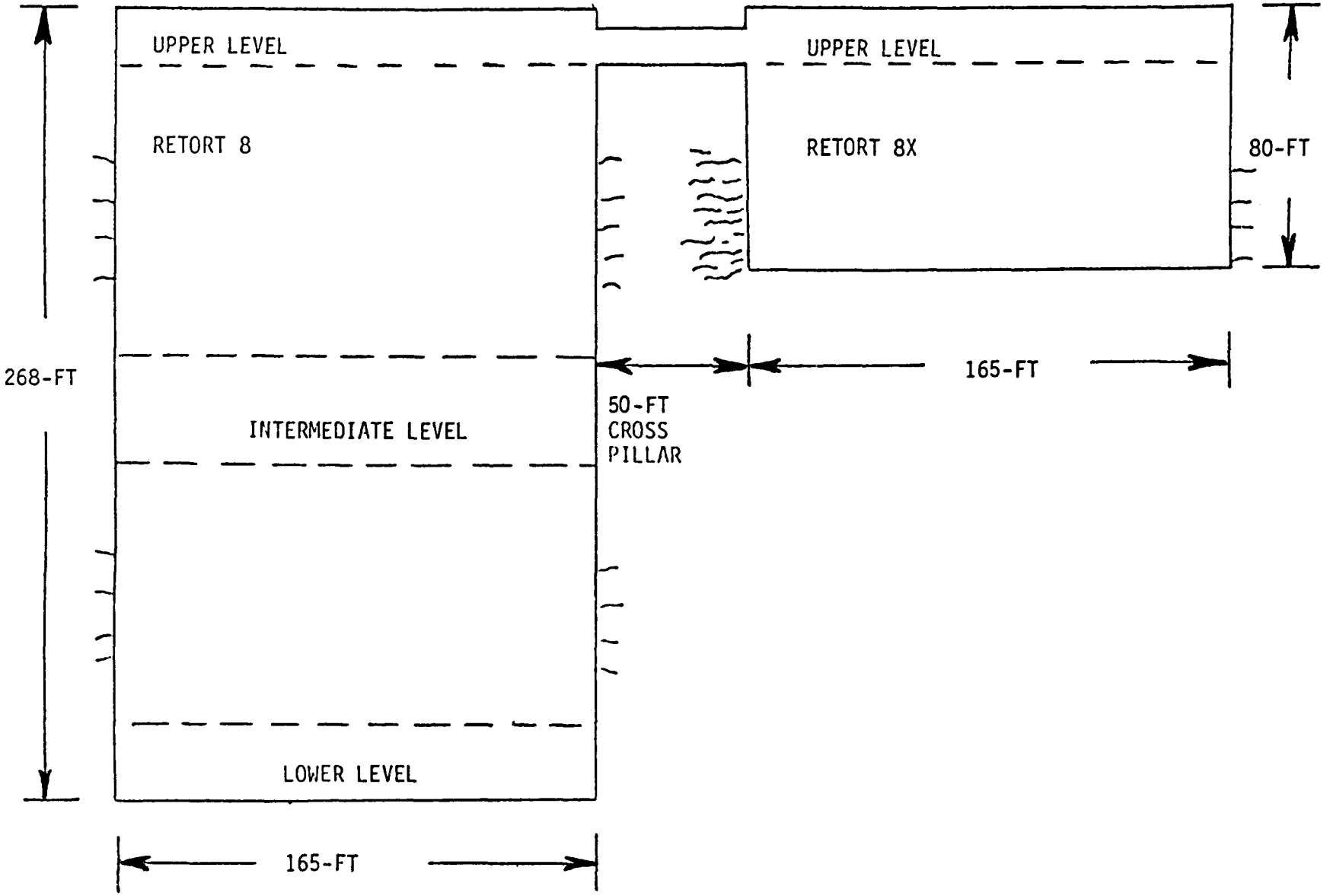


Figure 36. Damage present around Retorts 8 and 8X, cross section view.

IV. OOSI-FUNDED ROCK FRAGMENTATION PROGRAM

Early in the first quarter final preparations were made for rubbling Mini-Retort 4 on June 13. Cribbing, camera housing and mucking at the Product and Intermediate Levels were completed and preshot surveys were conducted. MR4 was rubbled at 4:45 p.m. on Friday, June 13, 1980, and postshot surveys found the rubble pile to be fairly flat and the void above the pile to be approximately five feet.

In preparation for pillar destruction during the R7 and 8 rubbling, two one-half-scale pillar tests were included in OOSI's Rock Fragmentation Program: PT-1L, the first pillar test, was detonated on June 27; PT-2L, the second pillar test, was detonated on August 28. The studies included preshot surveys, fracture mapping, instrumentation, and postshot surveys.

OOSI also funded full-scale operational tests designed to simulate the loading conditions and the lengthy loading cycle for R7 and 8 when some of the explosive will sit in the blast holes for more than four days. These tests compare products from various explosives suppliers. Three operational test holes at the surface were loaded on July 14 and detonated on July 18. The top decks in each were bulk loaded and one of these did not detonate. The hole later was cleaned to the top of the powder column and the remainder of the explosive was detonated. On September 22, two full-scale operational test holes (FSOP) were loaded and four days later were detonated. During October further FSOP tests were conducted and on October 28, test holes 6, 7, 8, and 9, located underground and loaded with a pumpable DuPont bulk product, were loaded. On November 3, three detonated, but at a low-order velocity; one misfired but was reprimed and shot on November 4. With the low-order detonation of one of the products, a decision was made to use the packaged product used for Retorts 5 and 6 in Retort 7, 8, and 8X.

A quarter-scale array floor shot (FS-8L), using a bulk product was conducted in October to compare the product with previous quarter-scale tests in the Rock Fragmentation Program that used different explosive products. At the end of November FSOP holes 10, 11, and 12 were loaded with the packaged product for detonation seven days later, on December 5. Pillar test holes loaded pneumatically with a cartridged product and having a seven-day wait time also were planned. The final four horizontal pillar test holes were shot on December 9 and delay-cap tests on caps to be used in Retorts 7 and 8 were conducted in January.

To further understand the state of the rubble in MR3, which was shot in April of 1980, OOSI started in July to core the rubble in the tightest region of the retort. No solid rock was cored and the rock looked well fragmented. The MR3 down-shot to bulk full the retort was detonated on August 12 and a postshot survey reported that in a major portion of MR3 the void was under one foot, at the burner hole in the center portion the void was only six inches. This is considered to be a bulked-full configuration.

Prior to the MR4 detonation in June, the U. S. Bureau of Mines (USBM) Twin Cities Research Center (TCRC) personnel attempted to conduct blast damage cross-borehole tests in MR3. No data was obtained because of equipment failure, but the USBM-TCRC personnel returned in mid-August and conducted cross-borehole studies in MR3 and MR4 through the end of the month.

Fracture mapping of R8X and R7 was done during the quarter December 1980 through February 1981 but rock fragmentation activities declined during the quarter because the efforts of personnel were directed to preparation for and detonation of R8X and R7.

V. DOE-FUNDED SUPPORT

A. HFEM EVALUATION

As a part of the DOE-funded instrumentation program, high-frequency electromagnetic mapping (HFEM) has been tested as a rubble evaluation technique. Prior to the MR4 detonation in June 1980, Lawrence Livermore National Laboratory (LLNL) personnel conducted base line HFEM studies on the retort from June 6 through June 8 and then returned to conduct the postshot HFEM rubble evaluation tests from June 17 through 22. LLNL personnel removed their equipment in February and continued their analyses at their headquarters.

W. D. Daily, LLNL, will present a paper, titled "In Situ Oil Shale Retort Monitoring Using Geotomography", at the Society of Exploration Geophysicists Meeting, October 15, 1981, on the HFEM work.

B. PILLAR INSTRUMENTATION

MR3 and MR4 pillar instrumentation and the role of each party was planned by OOSI and Sandia personnel at meetings in July. The instruments were hard wired to Sandia's B-61 Trailer for monitoring and recording the data during August, the cables from the mini-retort area to the B-61 Trailer were hung, and Sandia personnel continued software development and system debugging work. Sandia recorded the pillar instrument data before, during and after ignition of both retorts. Preliminary analyses are underway. Sandia will probably issue a report in early- to mid-1982.

C. RETORT TRACER TESTING

During August, Sandia also assembled a prototype mass spectrometer system to be tested on MR4 for retort tracer testing. The system was shipped to Logan Wash from the Sandia Labs in September to attempt a cold flow test on MR4 before drilling of the MR4 rubble holes started on October 1. Significant testing could not be completed due to problems with site electrical power, the need for a

filter system to the trailer gas sample inputs, the work necessary to adapt the OOSI injection system to the mass spectrometer system, and the presence of a large amount of water in the MR4 rubble bed. The instrumentation trailer was returned to Sandia for additional work. A program was to be pursued to verify the system in the laboratory and possibly run cold tests on MR5 and hot tests on MR4 prior to testing Retorts 7 and 8.

D. DATA ACQUISITION AND RECORDING SYSTEMS

Sandia began assembling thermocouple strings for MR3 during the quarter June through August and completed the assembly in September. They were installed following grouting of the casings in the instrument drill holes. Cabling was pulled from the entry drift to each zone box, and each thermocouple lead and uphole cable lead was wired at the zone boxes and entry-drift junction boxes. Software to control and manage the data taken from the thermocouples and the process instrumentation was completed and entered into the computer in September. A special phone line serves computer communication between Logan Wash, the DOE in Grand Junction, and Sandia Labs in Albuquerque.

The data acquisition and recording system for MR3 was completed and tested during the quarter September through November. Capabilities of the system are: collecting and processing information pertinent to monitoring and control of the retorting processes; analyzing data obtained from measurements such as thermal, flow, gas composition, and manually entered measurements to give derived information, including information concerning mass balances and burner performance; displaying the results of calculations on two sets of two TV monitors and displaying real-time control parameters such as retort and burner temperatures and flows on the monitors. Also, permanent records can be obtained in the form of lists or plots of any measured or known process variable versus another. For example, sectional views of temperature contours in the retort can be plotted for specified process times.

Four main terminals associated with the B-61 Trailer and three remote terminals are supported by the data acquisition system. Each of the remote data links provides a specialized subset of the information processing capability of the main work stations in B-61. They are tailored to the data display and processing requirements at terminals in the Grand Junction DOE office, the OOSI control room, and the OOSI gas chromatograph shed.

After termination of the unsuccessful MR3 ignition attempt, cables connecting the data acquisition and recording system with the MR3 thermocouples were cut at the entry drift Nema boxes, and multi-pin connectors were installed to allow connection to MR4 cables. The instrumentation and monitoring equipment for MR4 was essentially the same as that used for the MR3 ignition: approximately 265 thermocouples were divided between the sill and rubble bed to sense sill and rubble temperatures; burner operation, hot gas input, and output gas and liquid parameters were recorded. MR4 was started on January 9 using a hot inert gas generator, and rubble bed and sill temperatures were recorded by Sandia during the entire heating period. Sandia's diagnostic programs indicate that some thermocouples failed due to the severe thermo-chemical environment. Some problems with the data acquisition and recording system were encountered during the MR4 ignition experiment but sufficient data were collected and analyzed and a preliminary analysis of the events during the ignition phase was possible as discussed in Section III.4.

On March 24, Sandia initiated the conversion of the Mod Comp computer to the MR3 program. OOSI installed connectors on the MR3 thermocouple cables and performed a pin-to-pin check. A preliminary check of the thermocouples with B-61 indicated that most of them were still in good condition. Sandia and OOSI started working on the algorithms for the process data. The MR3 restart test was initiated on April 27 with retorting conditions and burner shutdown occurring on April 29.

E. RETORT 7 AND 8 INSTRUMENTATION

During the quarter March through May, Sandia and OOSI continued to work on details of the instrumentation and schedules for Retorts 7 and 8. Sandia agreed to pursue the fabrication and checkout of two cold gas tracer trailers with 15 channels each. By April the tracer trailer development testing was completed at the three-channel level and the first trailer was to be reworked to incorporate a 15-channel capability. The remaining equipment to complete the second trailer was ordered.

Sandia personnel began installing instrumentation for Retorts 7 and 8 during May. Thermocouple materials were moved into a work area in the mine, and the hole-logging trailer was set and subjected to an initial checkout. Routine logging and thermocouple installations were scheduled to begin during the first week of June.

As a result of a reevaluation of the drilling and instrumentation plans during November and December, it was decided to reduce the total drill hole length and the amount of instrumentation provided. Under the current plan, assuming a drilling rate of 50 feet per day per shift, and reasonable lead times for drilling, directional logging, instrument insertion, and grouting activities, four to five months will be needed to prepare the thermal and gas-sampling instrumentation in R7 and 8. Each hole will contain a stainless steel gas-sampling tube and an average of six thermocouples. The thermocouples will sense temperatures in the rubble beds and near the rubble bed and back interfaces of both retorts. R7 will have fewer instrumentation points than R8, but sufficient to verify that its retorting proceeds in a manner similar to R8. Both retorts will be supplied with approximately 100 channels of process instrumentation to collect data providing information concerning input gas and output gas parameters, ignition system performance and product output.

F. RETORT 3E ANALYSIS

The analysis of the Retort 3E spent shale core appears in a recently released DOE report along with analyses of oil, water, gas and air samples collected during Retort 6 operation. This report, Environmental Research on a Modified In Situ Oil Shale Process: A Progress Report from the Oil Shale Task Force, DOE/EV-0078, May 1980, is available from the National Technical Information Service (NTIS) in Springfield, VA.

VI. MINE STABILITY

A. RETORT 6

The program for mine design and stability with the U. S. Bureau of Mines (USBM), begun in 1977, has been completed. The three major program elements identified as important items directly relating to the safety of mining personnel and the development and design of economic mining methods in oil shale are:

- evaluation of loading conditions relevant to the retort;
- evaluation of subsidence potential; and
- determination of criteria for establishing a mining level.

To accomplish the program, a number of tests and monitoring activities were performed. Before the rubbling of Retort 6, strain relief overcoring was done to determine wall stress and the relieved core stress; spent shale tests were run to develop compaction vs. load properties; physical property tests were run for pillar and rock strength and compared with assays taken from core samples.

The outline of this program was presented in Appendix G of the Phase I First Annual Progress Report. Correspondence from the USBM to OOSI, discussing preliminary analyses and transmitting data, has been included in Appendix B of the Phase II Quarterly Progress Report for the period June through August 1980. The report on this work, Mechanical Properties, In Situ Stress and Temperature Measurements - Logan Wash Oil Shale Site, by F.G. Horino, D.R. Dolinar and D.L. Bickel of the Denver Research Center (Progress Report No. 10025) is in Appendix B of this report.

B. RETORTS 7, 8 AND 8X PROGRAM

By the end of June, RM-1 and RM-4 anchors, protective wellheads and the rod extensometer heads were installed in the Upper Level U-370-N drift thereby completing the scheduled rock mechanics

instruments for that drift. Early in July two stress meters and three rod extensometers were installed in the pillars between R7 and 8 from the L-260-N drift on the Intermediate Level. Two of the rod extensometers were placed horizontally, one was angled 45 degrees downward. Early in September, stress gages were installed in the U-370-N and L-260-N instrument drifts between R7 and 8 on the Upper and Intermediate Levels, respectively.

Details of the mine stability instrumentation are given in Appendix C of the Quarterly Report for June through August 1980.

C. MINI-RETORTS 3 AND 4

In order to study sill pillar behavior during ignition, OOSI expanded its instrumentation program to instrument the MR3 and 4 sill pillars with rod extensometers, pillar displacement indicators and pillar thermocouples. The instrument layout was developed during July, and extensometers were installed in the MR3 and 4 sill pillars during the quarter September through November.

D. CORING

Core samples from the Research Mine and the U-370-N and L-662-N instrument drifts were boxed during the quarter September through November and shipped to OOSI's Grand Junction Laboratory for storage. There are no plans for analyzing any of these cores.

A core from the MR3 upper level was shipped to the USBM for testing (microfracturing) during the quarter September through November. A report should be available from the USBM in 1982.

E. MONITORING

Mine stability and rock mechanics instrumentation have been monitored continuously since June 1980. Portions of this data are available and included in Appendix C of this report.

VII. PHASE II INSTRUMENTATION PLAN

Documentation of the Instrumentation Plan for Phase II began in May 1980. The following is a summary of primary areas of technical development in the Phase II program and the instrumentation plans for each of those areas as presented in Appendix C of the Quarterly Progress Report for the period June through August 1980:

- Rock Mechanics

  extensometers--monitor rock displacement and strain in the pillars surrounding the retorts throughout mining, blasting, and retorting;

  vibrating wire stress meters--measure stress change in the pillar between R7 and 8;

  thermocouples--monitor heat transfer into the pillars surrounding the retorts; and

  overcoring--determine the in situ stress field in the product level, pillar ribs, and retort roof.

- Rock Fragmentation

  high speed photography, down hole detonation detectors, seismic monitors, and air blast monitors--evaluate blast performance and rock blast damage in the mine around the retorts.

- Rubble Evaluation

  sulfur hexafluoride tracer testing--rubble evaluation;

  mass spectrometer system (Sandia Laboratories)--tracer tests with noble gases during retorting;

  high frequency electromagnetic mapping (Lawrence Livermore Laboratory and Occidental Research Corporation)--rubble evaluation; and

  pressure measurements--determine pressure drop through rubble as a function of retort geometry and gas flow rate.

- Processing

  Conventional process instrumentation--monitor flow, temperature pressure, and composition of the retort inlet and outlet streams and at key points in the offgas, oil and water handling streams;

  isokinetic sampling (EPA Method 5 type impinger train)--monitor offgas oil aerosol and water vapor concentations; and

  thermocouples and sample taps--temperatures and gas chromatorgraph analyses evaluate retorting.

An updated schedule of Phase II instrumentation activities, the planned instrument installation period and date of the event are presented in Table XV.

TABLE XV
PHASE II INSTRUMENTATION SCHEDULE

ACTIVITY	INSTRUMENT INSTALLATION PERIOD	DATE OF EVENT
ROCK MECHANICS INSTALLATION		
Surface	2/80-3/80	NA
Upper Level	5/80-6/80	NA
Intermediate Level	6/80-7/80	NA
RUBBLING		
Retorts 7, 8 and 8X	12/80-4/81	1/81-4/81
RUBBLE EVALUATION TESTS		
MR3 Tracer	5/80-6/80	6/80-7/80
MR4 Tracer	7/80-8/80	8/80-9/80
Retorts 7 & 8 Tracer	1/81-8/81	10/81-12/81
RETORTING TESTS		
MR3 Start-up	10/80-11/80 and 2/81-3/81	11/80-12/80 and 3/81-4/81
MR4 Start-up	11/80-12/80	12/80-1/81
Retorts 7 & 8 Start-up and Retorting	8/81-10/81	11/81-8/82
OFFGAS HANDLING		
Contact Condenser System	4/81-9/81	11/81-8/82
Offgas Compressor Train	8/81-9/81	11/81-8/82
SHUTDOWN	NA	8/82-11/82

VIII. ENVIRONMENTAL SUPPORT

The purpose of this section is to present a summary of permit status and to update the environmental monitoring and analyses performed in conjunction with oil shale retorting development and demonstration activities at the Occidental Oil Shale, Inc., Logan Wash mine site. Environmental monitoring has been conducted in accordance with requirements of applicable permits and the Environmental Research Plan submitted under the DOE contract. This report covers the period commencing in May 1980 and extending through April 1981. Data not previously reported are also included.

A. PERMITS

All permits and their status are reported to DOE in the quarterly reports. Table XVI lists all current permits associated with the Logan Wash project. It should be noted that there are three new items that were not in the 1980 Annual Report. These include a new Water Right - Permit, CW-24; a solid waste notice under Resource Conservation and Recovery Act (RCRA) - Environmental Protection Agency (EPA) ID COD 00824128, which is an interim status permit; and a toxic substance notice under Toxic Substance Control Act (TSCA) which would regulate production, distribution, and end use of the shale oil.

B. ENVIRONMENTAL MONITORING STATUS

1. Introduction and Summary

In accordance with applicable permits and the Environmental Research Plan prepared under the DOE contract, environmental data are currently being collected for various air, water and biological related parameters. The purpose of this report is to provide a summary of the environmental monitoring being performed in conjunction with the oil shale demonstration activities at the Logan Wash mining facility.

TABLE XVI
LOGAN WASH PERMIT STATUS REPORT
Current Permits/Notices

Compilation Date: 6/2/81

	Permit Title	Purpose	Permitting Agency	Permit No.	Date Submitted	Date Approved	Date of Expiration	Remarks
Air								
1)	PSD	Operate Retorts 7 & 8	EPA		3/24/79	11/01/79		
2)	Emission Permit (APEN)	Screening Plant	CAPCD	C-10,619	2/19/75	3/03/75	Indefinite	
3)	Emission Permit (APEN)	Shale Oil Heater	CAPCD	C-10,761	3/28/75	4/22/75	Indefinite	
4)	Emission Permit (APEN)	Hot Water Circulator (HT)	CAPCD	C-10,762	3/28/75	4/22/75	Indefinite	
5)	Emission Permit (APEN)	Hot Water Circulator (LB)	CAPCD	C-10,901	7/14/75	8/06/75	Indefinite	
6)	Emission Permit (APEN)	Retort 6	CAPCD	C-10,454/ C-11,708			Indefinite	
7)	Emission Permit (APEN)	Retort 7	CAPCD	C-12,319-1(SP)	1/26/79	7/25/79	Indefinite	Conditional to require testing of sulfur removal equipment.
8)	Emission Permit (APEN)	Retort 8	CAPCD	C-12,319-2(SP)	1/26/79	7/25/79	Indefinite	Conditional to require testing of sulfur removal equipment.
9)	Emission Permit (APEN)	Process Steam Boiler #1	CAPCD	C-12,319-3(SP)	1/26/79	7/25/79	Indefinite	
10)	Emission Permit (APEN)	Process Steam Boiler #2	CAPCD	C-12,319-4(SP)	1/26/79	7/25/79	Indefinite	
11)	Emission Permit (APEN)	Process Steam Boiler #3	CAPCD	C-12,319-5(SP)	1/26/79	7/25/79	Indefinite	
12)	Emission Permit (APEN)	Heater-Treater Expansion	CAPCD	C-13,005	7/24/80	1/28/81	Indefinite	

TABLE XVI (continued)
LOGAN WASH PERMIT STATUS REPORT
Current Permits/Notices

Compilation Date: 6/2/81

Permit Title	Purpose	Permitting Agency	Permit No.	Date Submitted	Date Approved	Date of Expiration	Remarks
Water							
1) NPDES (National Pollution Discharge Elimination System)	Mine Water Discharge	EPA/CWQCD	CO-0029947			12/31/83	Excess water discharged from the LWOS mine must be reported.
2) Subsurface Disposal (2) for Retorts 6, 7, & 8, and mini-retorts, subsequent adjacent retorts	Operate Retorts 6, 7, & 8 Operate mini-retorts	EPA/CWQCD		(6) 4/78 (7&8) 4/80	5/15/78 5/06/80	Indefinite Indefinite	Expanded monitoring under new plan commenced April 1.
3) 1900 GPD Sewage Plant	Sewage Treatment	Garfield Co.			2/19/76	Indefinite	
4) Sewage Plant Site Approval	Sewage Plant Location	Garfield Co.				Indefinite	
5) Water Well #2	Well #2 Construction	Garfield Co.	80320	6/02/75	8/07/75	Indefinite	
6) Water Right	Water Decree	Water Ct.	#5 W-1895	5/73	10/24/73	Indefinite	
7) Water Right	Water Decree	Water Ct.	#5 W-1896	5/73	10/24/73	Indefinite	
8) Water Right	Water Decree	Water Ct.	#5 W-1897	5/73	10/24/73	Indefinite	
9) Water Right	Water Decree	Water Ct.	#5 W-2223	5/73	5/21/74	Indefinite	
10) Water Right	Water Decree	Water Ct.	W-2539/WW-1	1/09/75	9/25/75	Indefinite	
11) Water Right	Water Decree	Water Ct.	#80 CW-24	2/28/80	8/80		

TABLE XVI (continued)
LOGAN WASH PERMIT STATUS REPORT
Current Permits/Notices

Compilation Date: 6/2/81

Permit Title	Purpose	Permitting Agency	Permit No.	Date Submitted	Date Approved	Date of Expiration	Remarks
Land							
1) Special Land Use Permit	Observation Well (LW-112)	BLM	CO-76SL11 (GJ-6-105N)	2/18/76	4/22/76	4/21/81	
2) Temporary Use Permit	Flume - Smith Gulch	BLM	CO-070-TU-78-5	7/22/80	7/24/80	1/24/81	Renewed.
3) Temporary Use Permit	Flume - Riley Gulch	BLM	CO-070-TU-78-6	7/22/80	7/24/80	1/24/81	Renewed.
4) Temporary Use Permit	Observation Well and Flume - Bowdish Gulch	BLM	CO-070-TU-78-21	9/26/80	9/12/78	9/11/80	
5) Right-of-Way	Tramroad	BLM	C-23027	9/09/75	4/20/77	7/19/2007	Gate to mine and experimental adit.
6) Right-of-Way	Heater-Treater and Pipeline	BLM	C-22434	2/07/75	6/16/75	6/16/2005	
7) Special Land Use	Observation Well LW-101	BLM	CO-76SL4 GJ-6-53	9/26/80	11/01/75	10/31/80	
8) Special Land Use Permit	Observation Well LW-108	BLM	CO-76SL8	1/06/76	2/23/76	2/22/86	
9) Special Land Use Permit	Observation Well Shale 2	BLM	CO-76SL9 (GJ6-108)	2/28/76	4/22/76	4/21/81	
10) Special Land Use Permit	Observation Well LW-101A	BLM	CO-76SL10	2/18/76	4/22/76	4/21/81	

TABLE XVI (continued)
LOGAN WASH PERMIT STATUS REPORT
Current Permits/Notices

Compilation Date: 6/2/81

Permit Title	Purpose	Permitting Agency	Permit No.	Date Submitted	Date Approved	Date of Expiration	Remarks
11) Right-of-Way	Upper Road Access	BLM	CO-23027 CO-946	10/12/79	3/12/80	4/19/2007	
12) MLRB Permit	Surface Disturbance	CMLRB	77-424	3/28/78	4/01/80	3/27/2038	
13) Russell and Mary Hugh Scott Mark Longfield, Inv. Mgr.	Observation Well Smith Gulch	Private Property			8/26/75	8/26/85	
14) Exxon (Access/Right-of-way	Observation Well Kelly Gulch	Private Property			1/19/76	Indefinite	
15) Union Oil (Access/ Right-of-way	Observation Well Riley Gulch	Private Property			10/24/75	Indefinite	
16) Mineral Waste Dump	Mine Dump	Garfield Co.	131	1/19/76	5/01/76	When full	
17) Conditional Use Permit	Access Road & Benches	Garfield Co.	None Assigned	3/15/74	4/04/74	Indefinite	
18) Conditional Use Permit	Tank Farm & Gate	Garfield Co.	008	8/07/74	9/25/74	Indefinite	
19) Conditional Use Permit	6% Access Road	Garfield Co.	009	10/21/74	12/17/74	Indefinite	
20) Conditional Use Permit	69 KV Substation	Garfield Co.	011	5/75	6/04/75	Indefinite	
21) Conditional Use Permit	Heater-Treater & Pipeline	Garfield Co.	015	3/28/75	6/26/75	Indefinite	
22) Conditional Use Permit	69 KV Powerline	Garfield Co.	016	6/20/75	6/26/75	Indefinite	

TABLE XVI (continued)
LOGAN WASH PERMIT STATUS REPORT
Current Permits/Notices

Compilation Date: 6/2/81

Permit Title	Purpose	Permitting Agency	Permit No.	Date Submitted	Date Approved	Date of Expiration	Remarks
23) Temporary Trailer	Personnel Trailer	Garfield Co.	161	11/24/75	12/17/75	12/16/80	
24) Lease Agreement	Tank Farm and Gate	R. E. Prather & Getty Oil					
Solid Waste							
1) RCRA	Storage of hazardous wastes	EPA	EPA ID#COD 000824128	11/19/80			Interim Status Permit Final permit required at time of EPA request.
Toxic Substances							
1) TSCA-Premanufacture Notice-Shale Oil	Regulates all aspects of production, distribution and end use.	EPA		4/26/78	N/A	N/A	
Others							
1) Explosives Storage	Federal Government	Dept. of Treas.	5 CO-03833-AP-90124	9/28/76		12/31 Annually	Renewed January 1, 1981
2) Explosives Storage	Colo. Government	Co.Bu. Mines	418			12/31 Annually	Renewed January 1, 1981
3) Communication Station Authorization	Microwave System	FCC	None Issued	4/02/75	5/01/78	Indefinite	
4) Underground Flame Variance	Retorts 4, 5, & 6	CBM & MSHA		2/07/77	4/07/77	Upon shutdown of each retort	
5) Variance to CBM Bulletin 20	Alimak Hoist	CBM					
6) Radioactive Materials License	Krypton	Colo. Dept. Health	267-01		5/10/76	4/30/85	
7) Environmental Assessment	Phase II Cooperative Agreement	DOE	DOE/EA0095	1/79	Issued 11/79		COOP Agreement requires Environmental Monitoring and Sampling Plan for Phase II Retorts 7 & 8.

Environmental parameters which were being collected during the the 1980-81 reporting year in the Air and Water Monitoring Program are presented in Tables XVII and XVIII. Biology is discussed in Section VIII.B.4. These tables identify the stations in use as well as the parameters being measured. Also included in these tables are the station codes utilized in OOSI's computerized data base.

Water related areas which are examined include deep wells, alluvial wells, process water, surface flows, and waters in the mine itself. Parameters which are examined include depths, flows, and chemical characteristics. Applicable permits include Subsurface Disposal and National Pollution Discharge Elimination System (NPDES). High values for two NPDES effluent parameters, iron and total suspended solids, have been observed and reported over the past year, however, to resolve the situation, erosion control basins will be constructed at the base of the mine dump which is at the head of Logan Wash.

Air quality and meteorology parameters currently being monitored include suspended particulates, carbon monoxide, wind speed and direction, temperature, relative humidity, solar radiation and temperature inversion heights. The long-term purpose of the Air Quality Monitoring Program is to establish additional baseline data and monitor any effects retorting may have on the ambient air. One important observation noted was a significant decrease in total suspended particulates. This was probably due to a decrease in earthmoving activities and an increase in dust abatement practices at the site. During the summer of 1981, new air monitioring sites and equipment will be installed at Logan Wash. This new equipment, which will include H_2 monitors as well as new meteorological equipment, will greatly improve data quality and collection efficiency.

As part of the Biological Monitoring Program both floral and faunal surveys were performed during the summer of 1980.

TABLE XVII

AIR QUALITY/METEOROLOGICAL MONITORING STATIONS AT LOGAN WASH SITE

Station Location	Computer Code	Measurement	Elevation Level
Guard Gate	LW04	Temperature Relative Humidity	2 Meter
Heater Treater	LW01	Wind Direction Wind Speed Temperature	10 Meter
Lower Bench	LW03	Temperature Relative Humidity	2 Meter
Meteorological Tower	LW02	Particulates Temperature Relative Humidity Solar Radiation	2 Meter

TABLE XVIII
WATER MONITORING STATIONS AT LOGAN WASH SITE AND PRESENT MONITORING FREQUENCY REQUIREMENTS

Water Type	Station	Computer Code	Frequency
Alluvial Wells	LW22	LWA022	Monthly
	LW101A	LWA100	Monthly
	LW101	LWA101	*Monthly
	LW102	LWA102	Monthly
	LW103	LWA103	Quarterly
	LW104	LWA104	Quarterly
	LW112	LWA112	Monthly
	LW115	LWA115	Monthly
	LW121	LWA121	Monthly
Deep Wells	LW32	LWD032	Quarterly
	LW33	LWD033	Quarterly
	LW45	LWD045	Quarterly
	LW46	LWD046	Quarterly
	LW47	LWD047	Quarterly
	LW106	LWD106	Quarterly
	LW108	LWD108	**
	LW116	LWD116	Quarterly
Retort 6 Wells	LMB1	LWD601	Quarterly
	PLRL1	LWD602	Monthly
	LILSW1	LWD603	Monthly
	LILSE2	LWD604	Monthly
	LILN3	LWD605	Monthly
	L2PS1	LWD606	Monthly
	L2PS2	LWD607	Monthly
	UIL600	LWD608	Quarterly
	ALN1	LWD609	Abandoned
	UILSW1	LWD610	Monthly
	UILSE2	LWD611	Monthly
Springs	Spring 1	LWP001	(1)
	Spring 2	LWP002	(1)
Retorts 1-6	Top Retort 1	LWR000	Abandoned
	Bottom Retort 1	LWR001	Quarterly
	Bottom Retort 2	LWR002	Quarterly
	Bottom Retort 3	LWR003	Dry
	Bottom Retort 4	LWR004	Quarterly
	Bottom Retort 5	LWR005	Quarterly
	Bottom Retort 6	LWR006	Quarterly

* Alluvial well LW101 replaced by LW101A.
** Weekly before and during retorting, monthly after shutdown.
(1) Not required under present permit.

TABLE XVIII (continued)
WATER MONITORING STATIONS AT LOGAN WASH SITE

Water Type	Station	Computer Code	Frequency
Streams	Bowdish Gulch	LWS001	Monthly
	Logan Wash	LWS002	Monthly
	Upper Roan Creek	LWS003	Monthly
	Smith Gulch	LWS004	Monthly
	Kelly Gulch	LWS005	Quarterly
	Riley Gulch	LWS006	Quarterly
	Upper Parachute Creek	LWS007	Quarterly
	Dry Gulch	LWS008	Weekly if Flowing
	Lower Roan Creek	LWS013	Monthly
	Lower Parachute Creek	LWS017	Quarterly
Mine Discharge	Dry Gulch at Flume	LWM001	(2) Weekly
	Research Port Hole	LWM002	(2) Weekly

(2) When discharge occurs.

Results of the floral survey have shown little change in floristic diversity, however, the number of individuals and amount of vegetal cover have increased. Up to the present time, mining activities seem to have had little effect on vegetation and its growth. Impacts resulting from mining activities are minimized by reclamation and revegetation of disturbed areas.

The faunal survey consisted of collecting data on experimental and control plots in order to test the null hypothesis that mining activities are not affecting small mammals, birds, or deer. Small mammal abundance declined at the site between 1978 and 1980, however, this decline occurred on both experimental and control plots. Data on avian diversity and abundance at both lower and higher elevations tended to support the null hypothesis that mining activities are not affecting avian populations at the Logan Wash site. A comparison of mule deer census data for 1977, 1978, and 1980 suggested a slight decrease in the size of the resident herd since 1978, however this decrease is most likely attributable to the severe winter in 1978-79, and not to mining activities or other human perturbation. On the site in August 1980, cattle were more abundant than before. There was heavy impact on vegetation around water sources in Upper Fall, West Riley, and Northwest Riley Gulches.

A map showing the locations of the various monitoring installations is shown in Figure 37. The various types of monitoring stations are identified by different-shaped symbols. The locations of all retorts are shown for reference. Several water quality wells located within or near the retorts in the mine are not shown on this map but are shown in Figures 38 through 41. An isometric schematic showing Retort 6 water sampling well locations is presented in Figure 42. An elevation profile along a cut from alluvial well 101 to the Retort 6 stack, and then to the Meteorological Tower to depict

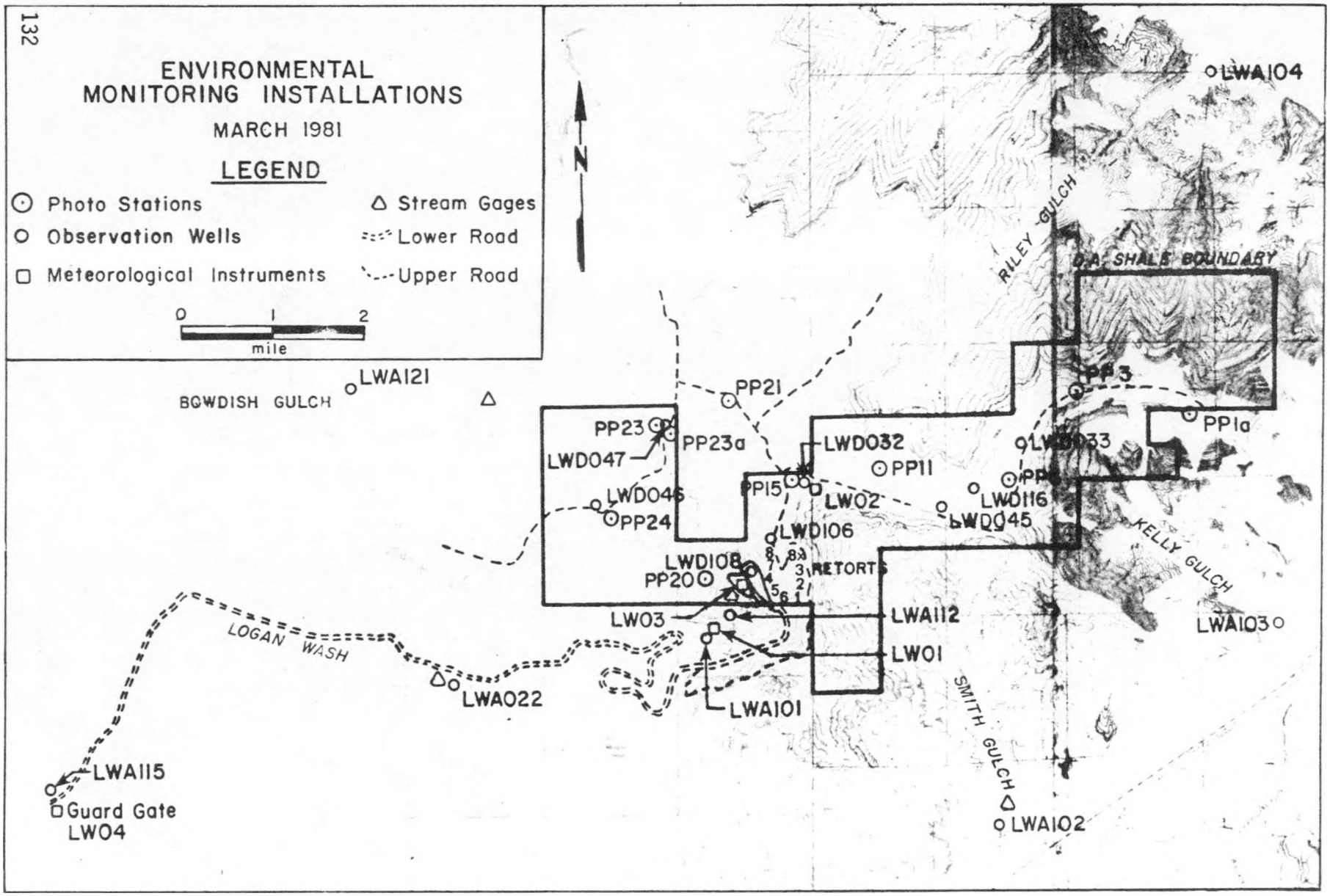


Figure 37. Location of Environmental Monitoring Installations at Logan Wash.

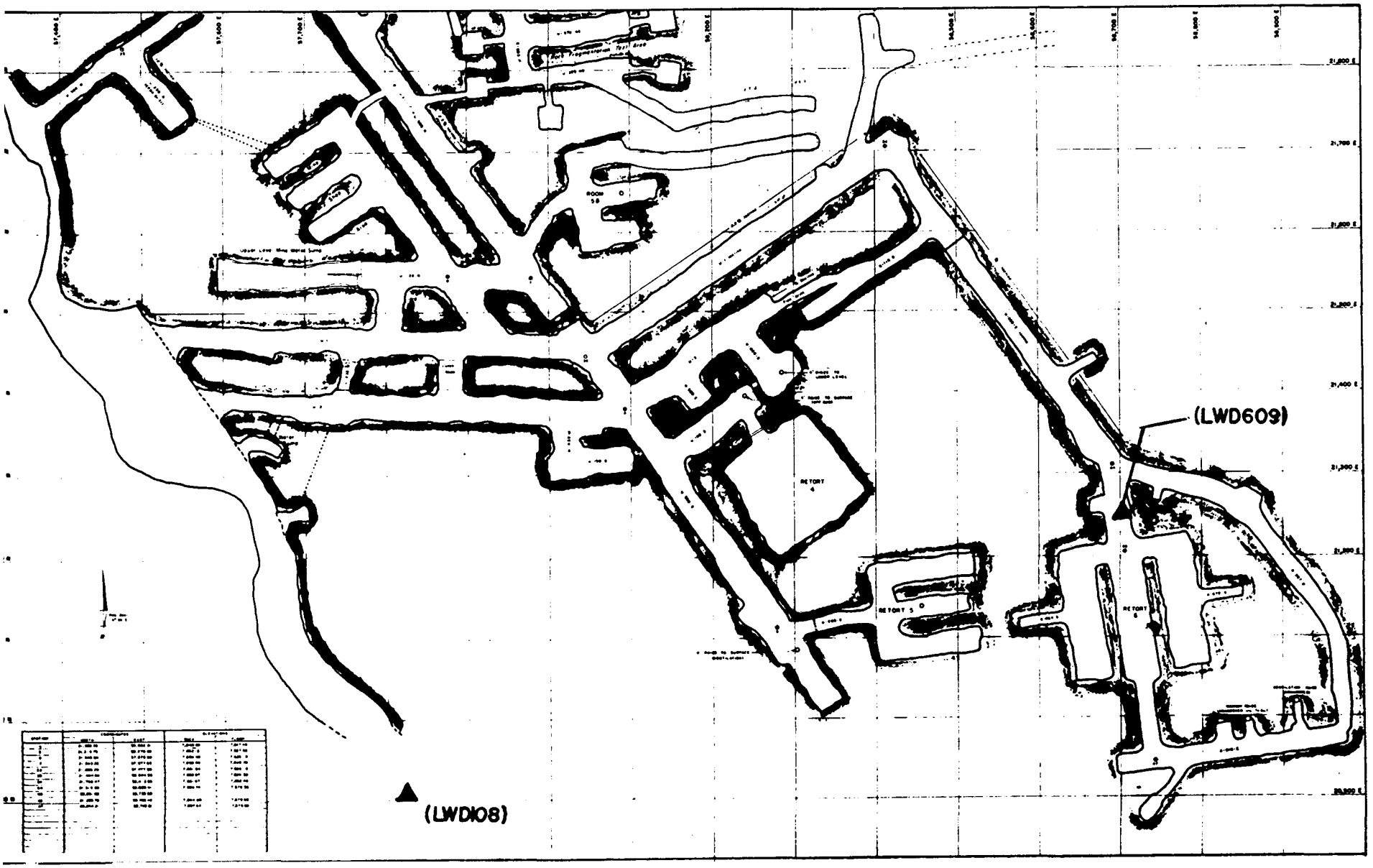


Figure 38. Well and deep well locations in Upper Level.

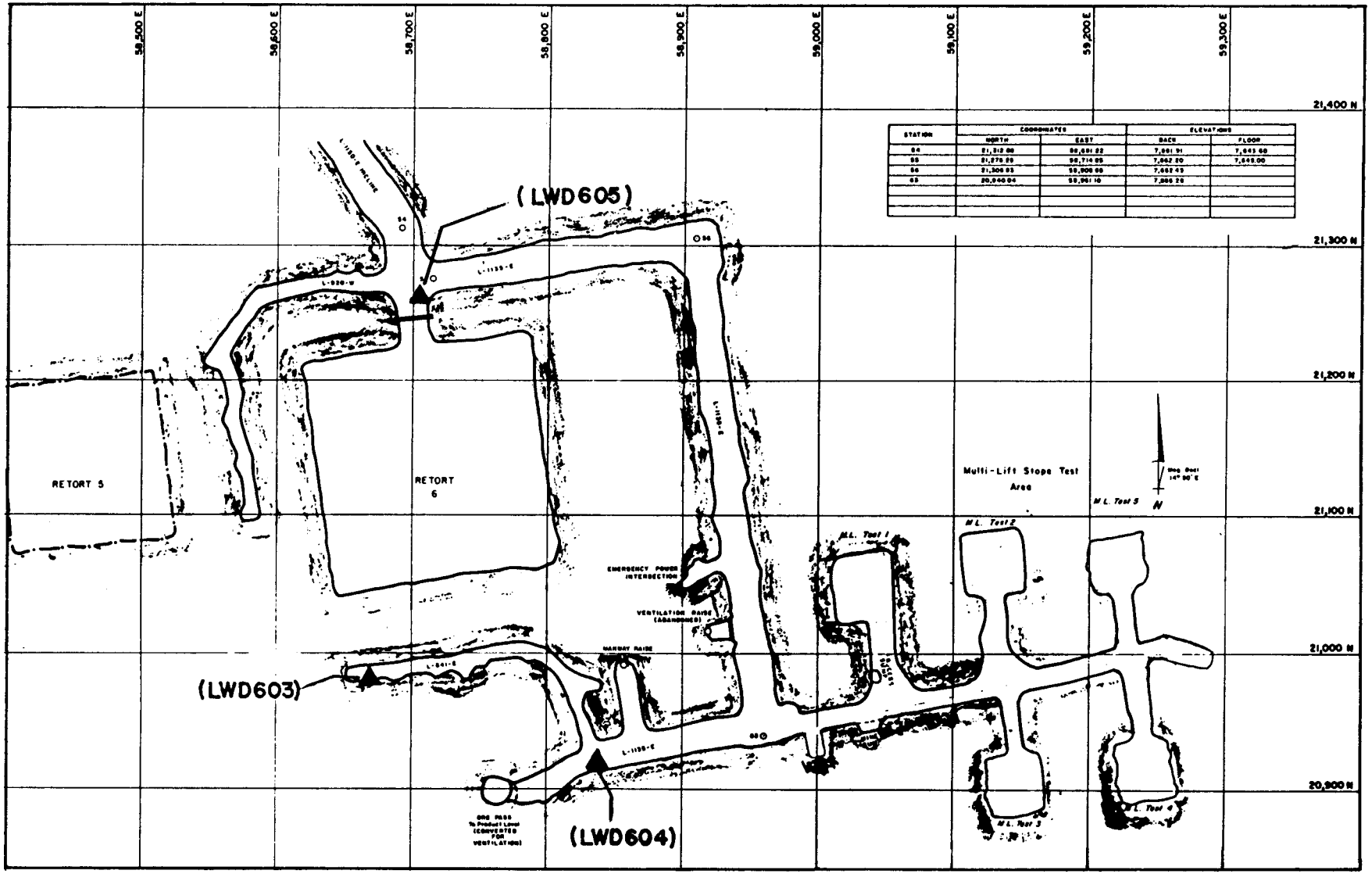


Figure 39. Well locations in Lower Intermediate Level, Retort 6.

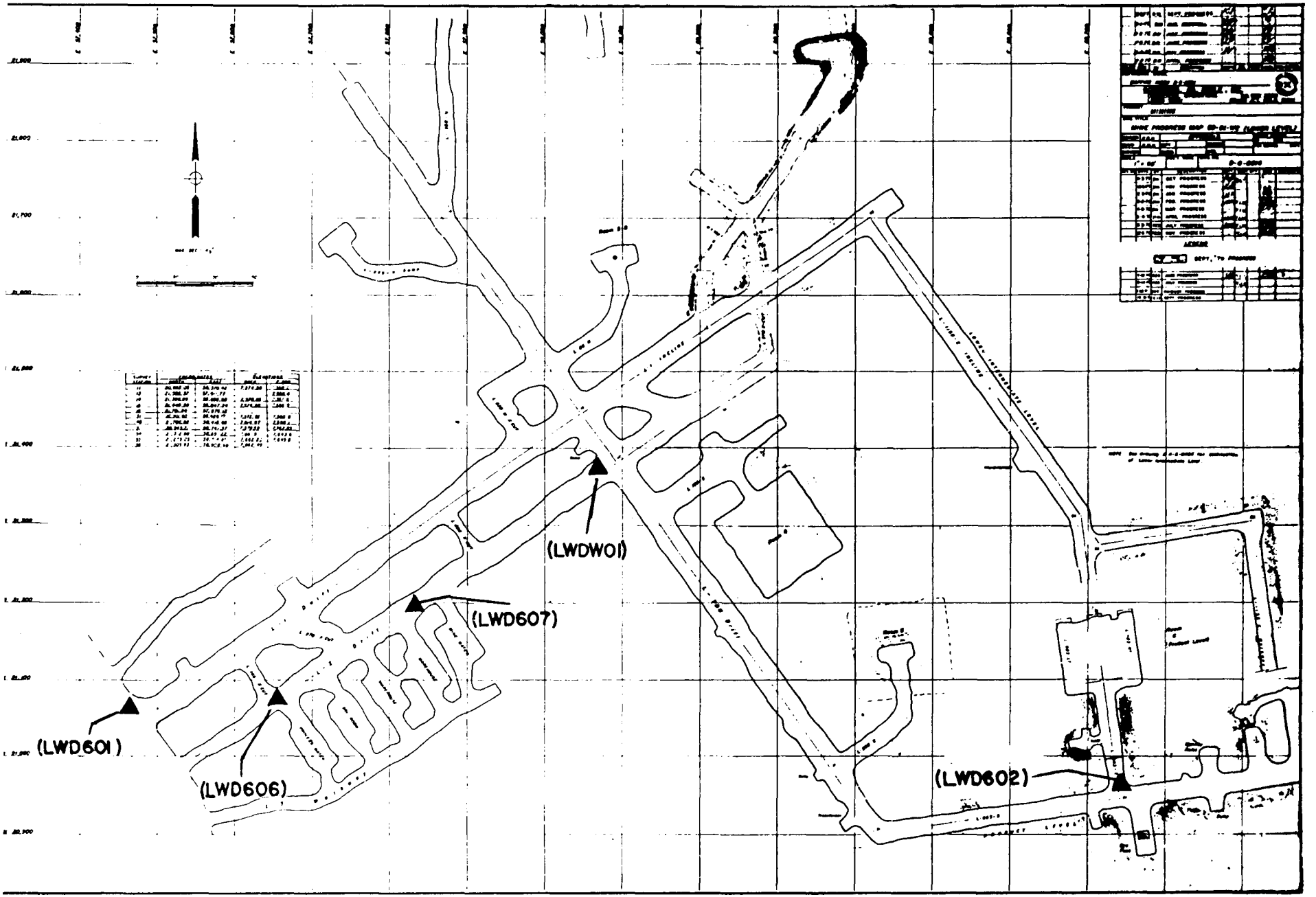
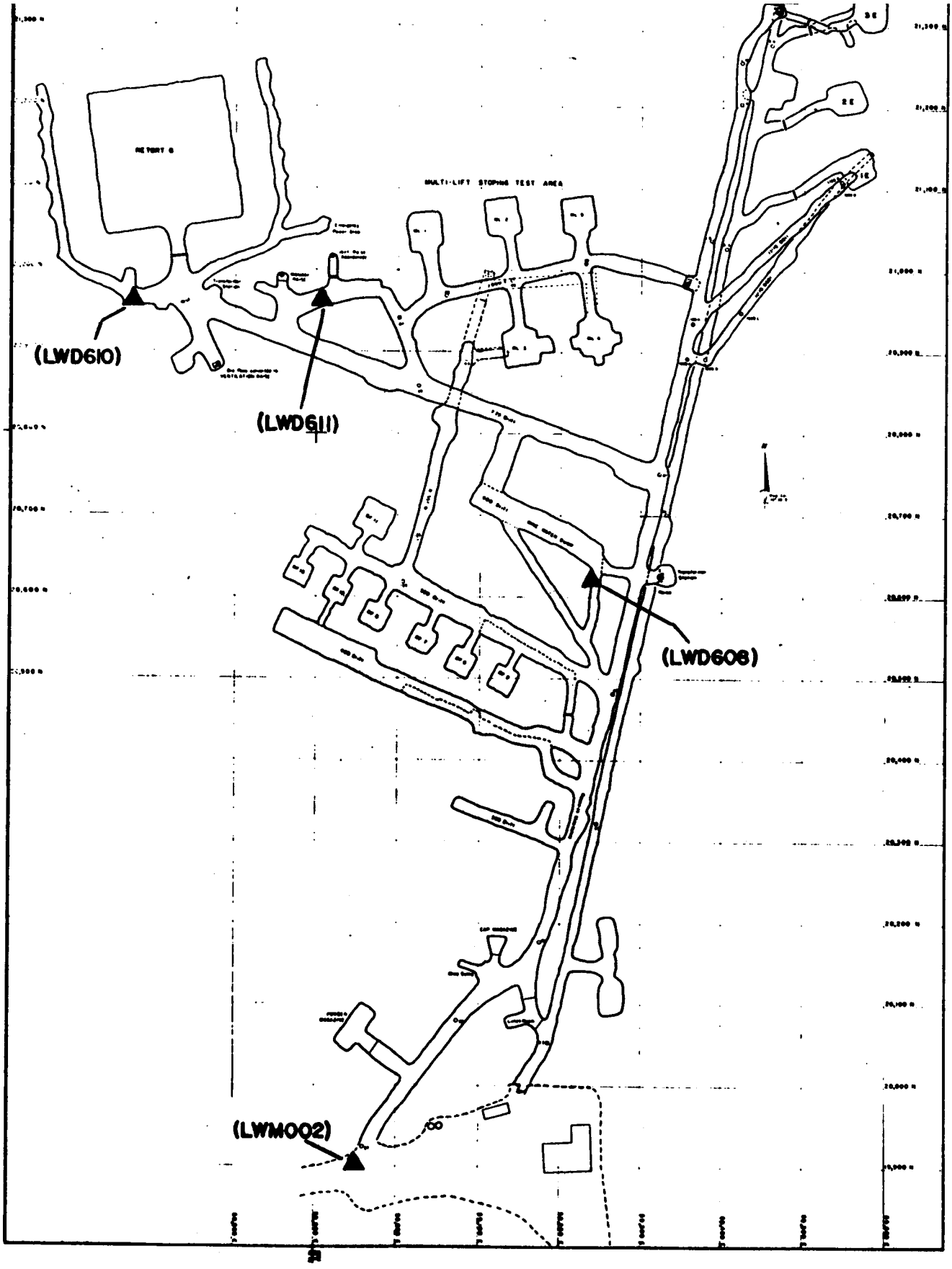


Figure 40. Well locations in Lower Level.



136 Figure 41. Well and discharge location at the Research Mine.

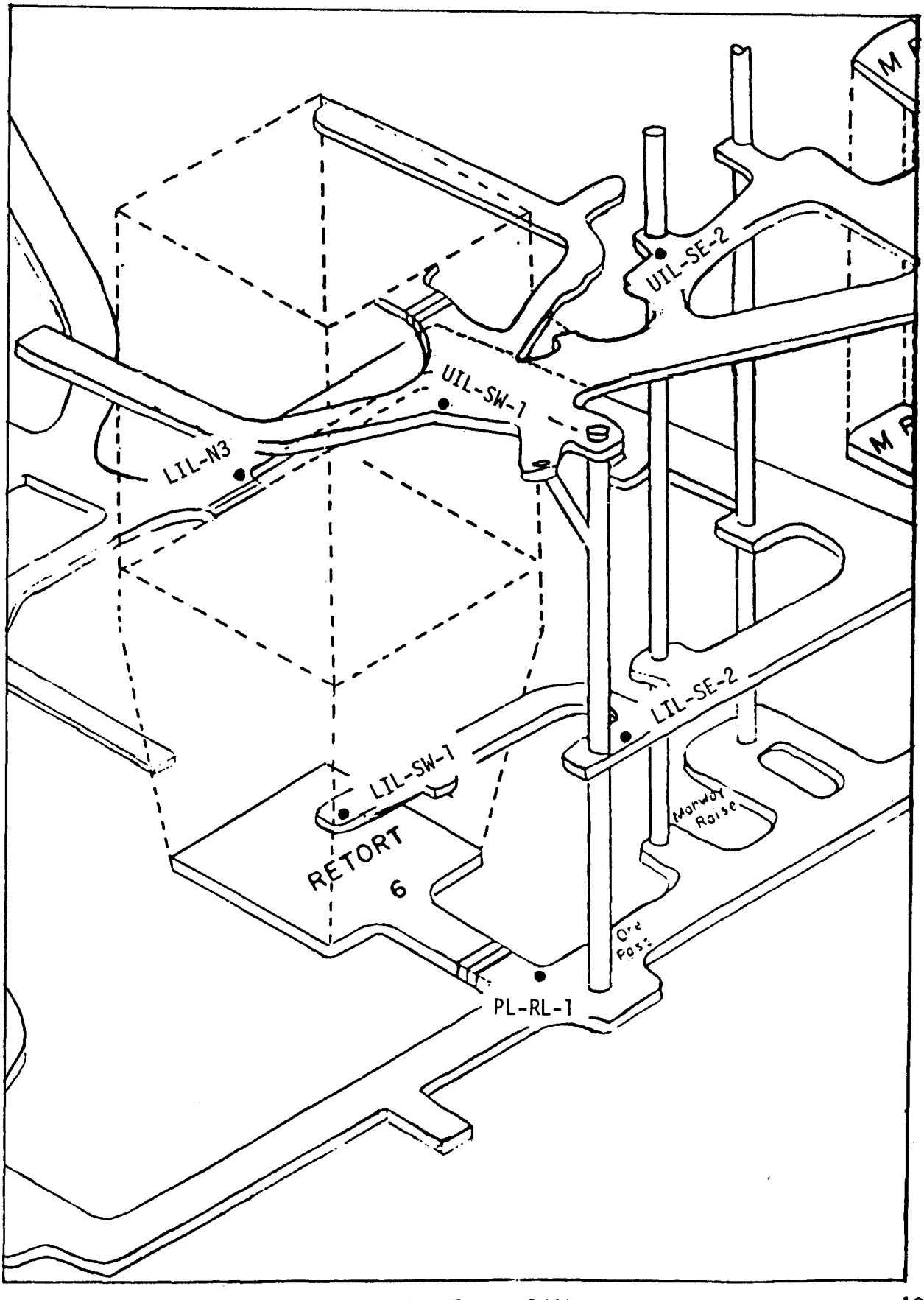


Figure 42. Isometric Schematic - Retort 6 Water Sampling Wells.

the terrain variations is shown in Figure 43. Even though the horizontal scale is compressed in the figure, the steep slope and elevation change are quite significant. An operational timeline for environmental monitoring equipment at Logan Wash is shown in Figure 44. Water sampling frequency, listed by site, is shown in Figure 45.

Appendix A, Section F, of the Cooperative Agreement (formerly No. EF-77-A-04-3873) between the U.S. Department of Energy (formerly the Energy Research and Development Administration) and Occidental Oil Shale, Inc., specifies the environmental requirements in the agreement. It calls for an Environmental Research Program structured and implemented to provide for the collection, evaluation, and reporting of environmental data. The following is a reference matrix to show compliance with Section F of Appendix A.

Appendix A, Section F	OOSI Progress Report
-Paragraph-	
a. Hydrology and water resources	Phase II, 2nd Annual Section VIII,B,2
b. Meteorology, air quality and gaseous emissions	Section VIII,B,3
c. Biological and health effects	Section VIII,B,4
d. Land and reclamation	Section VIII,B,4
e. Societal influences	Phase I, 1st Quarterly Appendix G Phase I, 5th Quarterly Appendix C Phase I, 2nd Annual Vol. III, Appendix L
f. Data required to obtain operating permits	Phase II, 2nd Annual Appendix A, Environmental

Items provided but not required by the cooperative agreement:

Photography Study	Phase II, 2nd Annual Section VIII,B,5
Quality Assurance	Section VIII,B,6

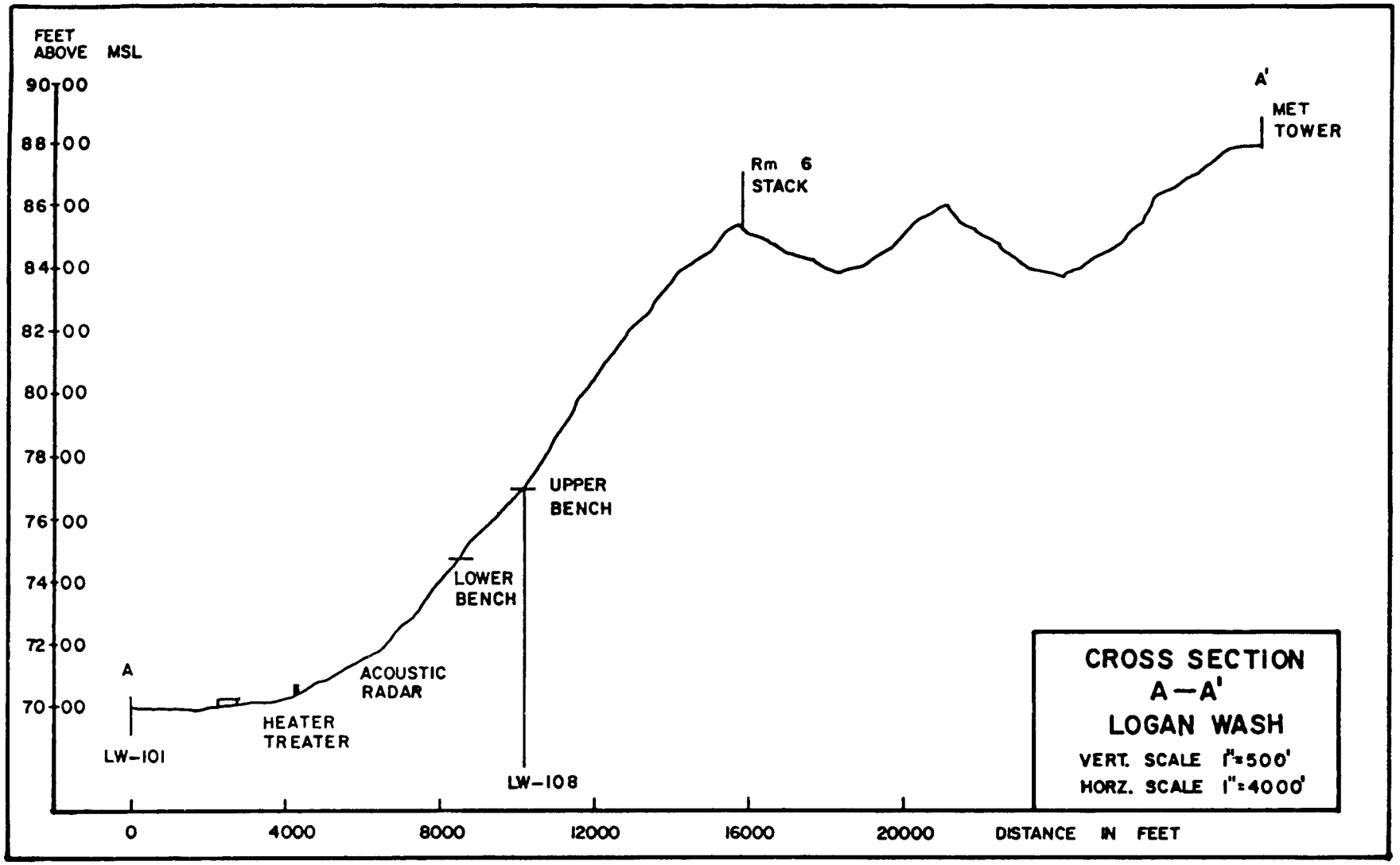


Figure 43. Elevation profile for Logan Wash mine area.

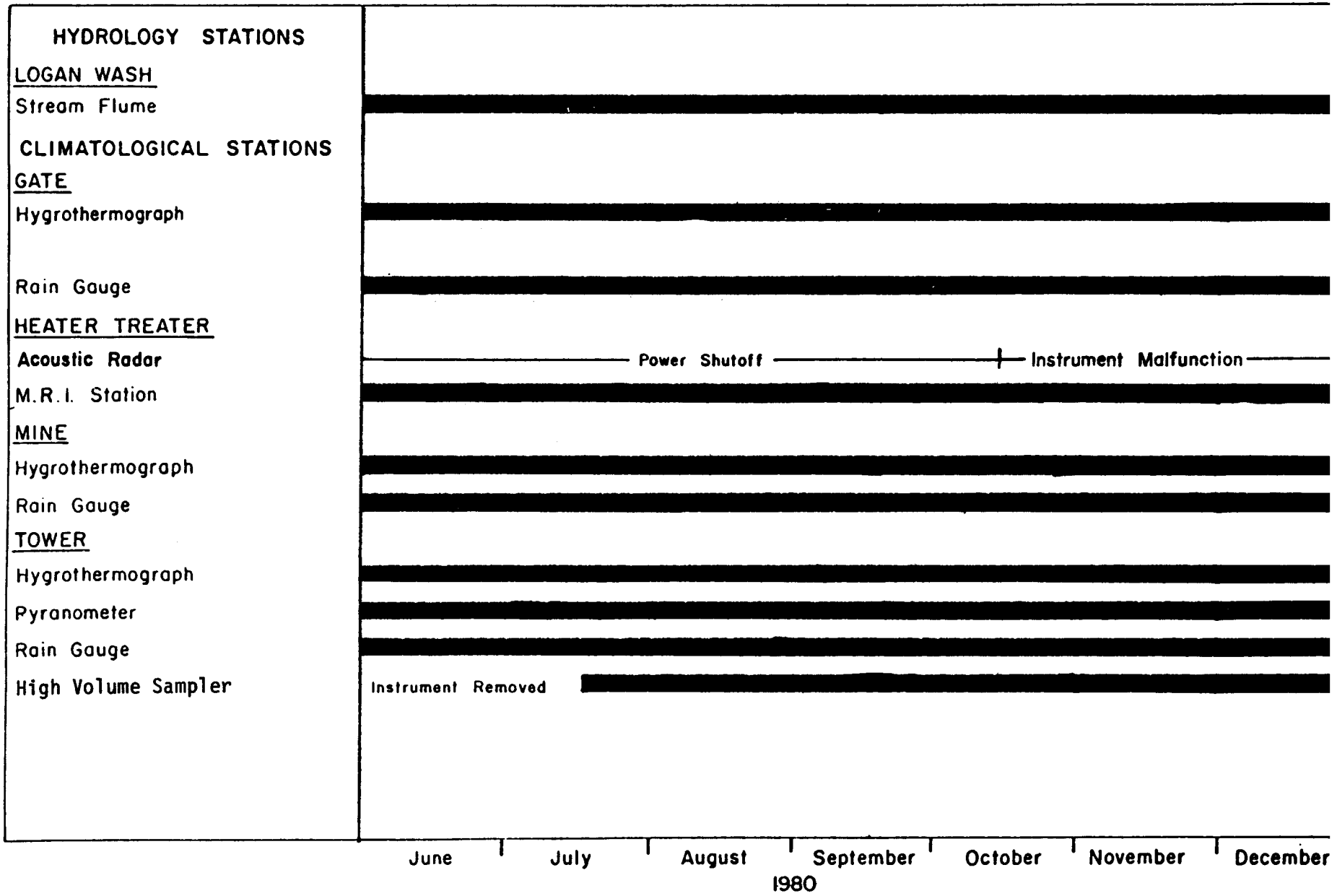


Figure 44. Operational timeline for Logan Wash.

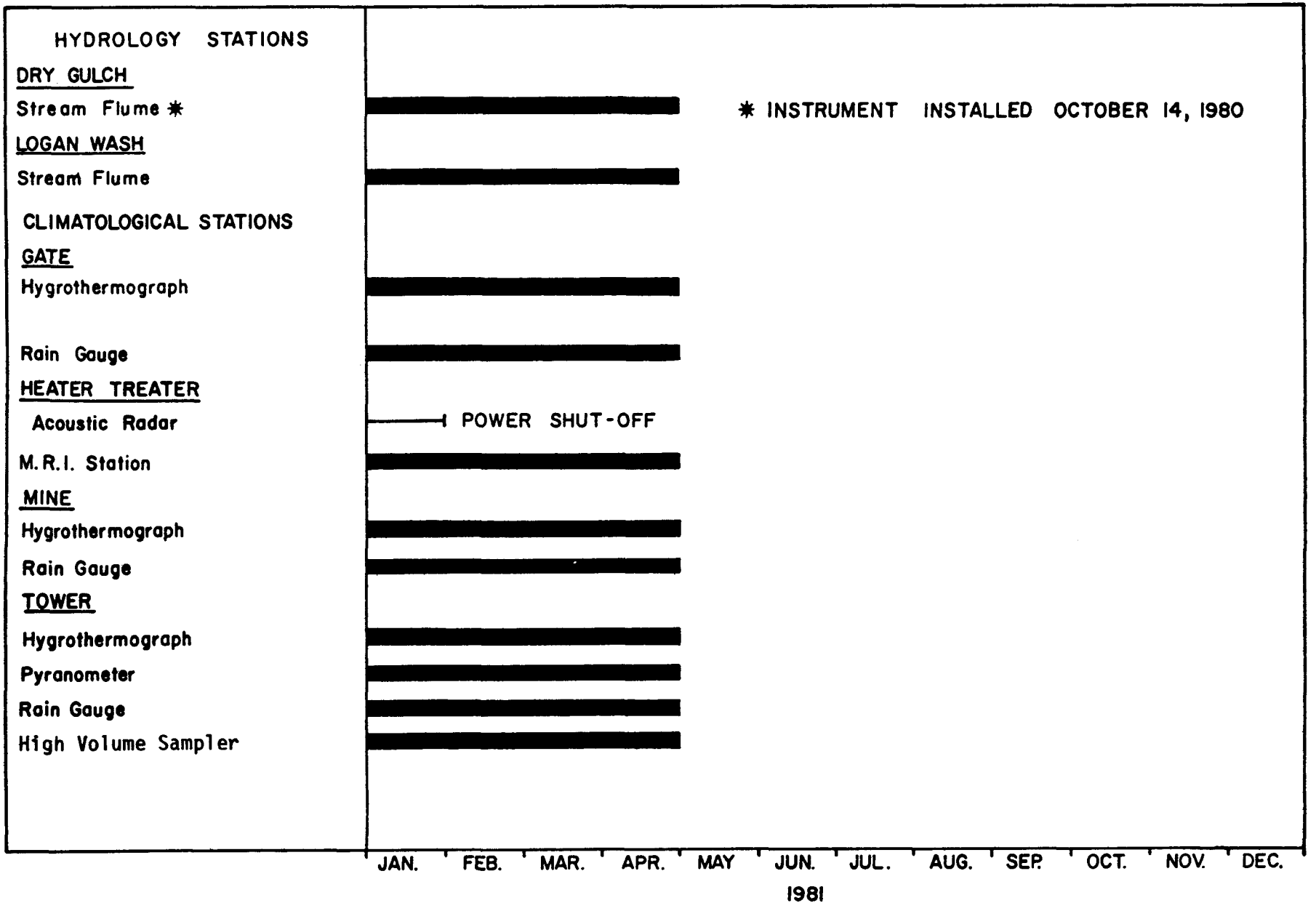


Figure 44. Operational timeline for Logan Wash. (continued)

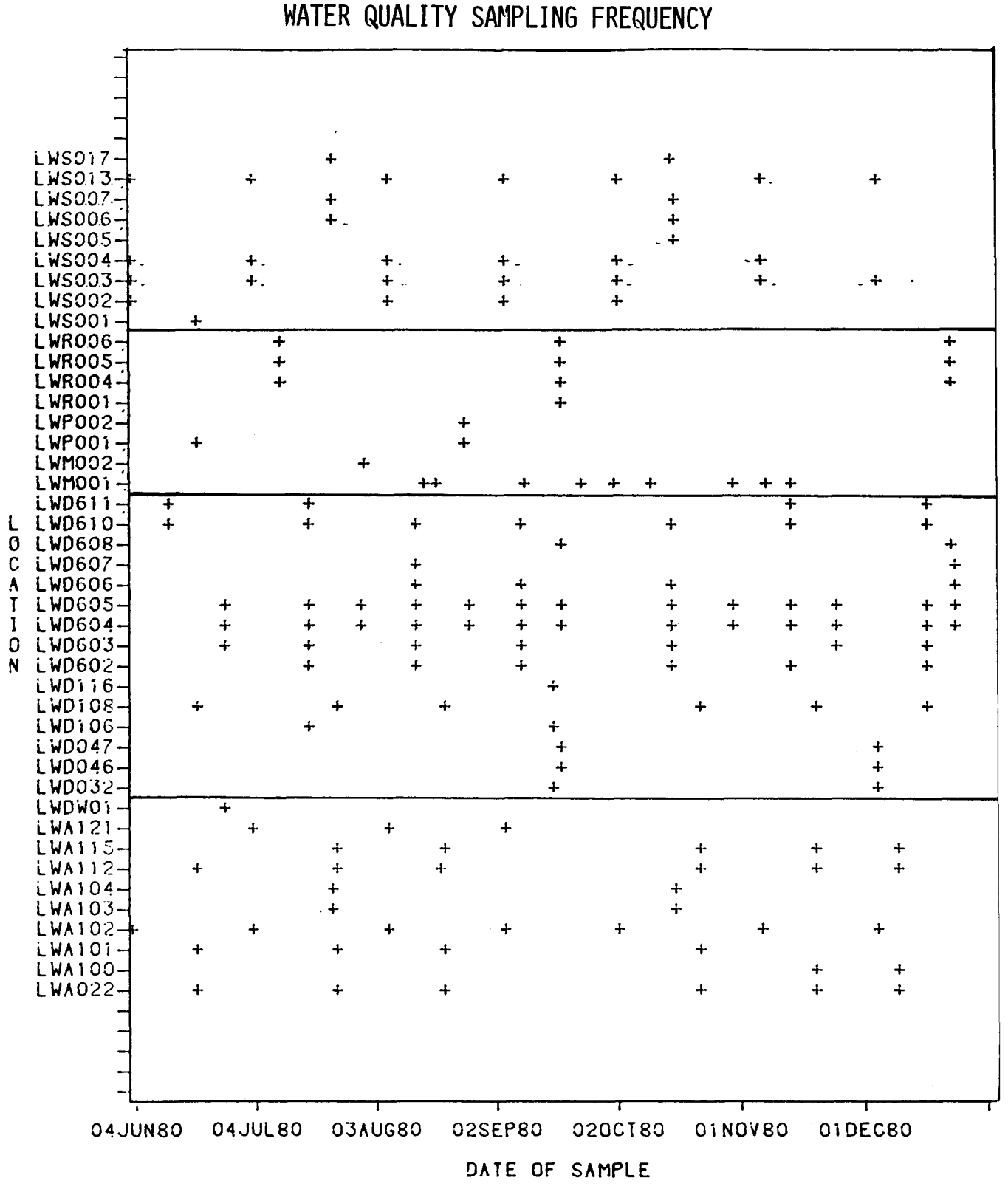


Figure 45. Water quality sampling frequency at Logan Wash mine site.

2. Hydrology and Water Quality

a. Introduction

In accordance with Occidental's contract with DOE, hydrology and water quality parameters are being monitored at the Logan Wash mining facility as required by permit conditions. In this way, Occidental can demonstrate that the waters of the State are not being polluted while acquiring more information about the MIS process and its affects, if any, on the natural hydrology of the area. Areas which are examined include deep wells, alluvial wells, process water, surface flows, and waters in the mine itself. Parameters which are examined include depths, flows, and chemical characteristics. Specific chemical analyses performed on the water samples are discussed in this report and are listed in Appendix D.

b. Permit Requirements and Experimental Design

(1) Subsurface Disposal

On April 1, 1981, a new Water Monitoring Program was initiated at Logan Wash in compliance with the subsurface disposal permit granted by the Colorado Department of Health and Water Quality Control Commission. This new program supercedes the previous permit requirements for subsurface disposal for the operation of Retort 6. The purpose of the new program is to ensure that pollution, if any, of the waters of the State, resulting from the proposed retorting system will be limited to waters in a specified limited area where there is no risk of significant migration, and that the proposed activity is justified by public need.

The previous program monitored waters from alluvial wells, deep wells and wells in the mine area, surface waters, and process waters. The alluvial wells included three in Logan Wash and one each in Smith, Riley, and Kelly Gulches. These were sampled monthly except for Kelly and Riley Gulches which were sampled quarterly. Four deep wells around the Tract were used to monitor ground water on a quarterly basis. The surface waters in Logan and Bowdish Washes and Smith Gulch were sampled monthly whenever flowing. Dry Gulch in the upper Logan Wash drainage was tested whenever flow occurred. Roan Creek was sampled monthly from sites above and below the mouth of Logan Wash. Parachute Creek was sampled quarterly above and below the mouth of Riley Gulch. Kelly and Riley Gulch surface flows were tested quarterly. Wells in the mine area include satellite wells located immediately adjacent to Retort 6 and other wells which monitor specific processing sites. These wells were sampled monthly except for the well location on the upper mine bench near the steam plant which was tested weekly before and during retorting and monthly thereafter. Waters from the process water sumps beneath the retorts were monitored three times before retorting began, weekly during retorting, and with a frequency after retorting which decreased from biweekly to quarterly.

Surface and alluvial waters were analyzed for color, odor, temperature, conductivity, pH, and dissolved oxygen in the field. In the laboratory the following tests were run: major cations (Na, Ca, K, Mg, and NH_3-N), major anions (NO_3, SO_4, Cl, HCO_3 and CO_3), trace elements (Si, Li, Mo, Zn, F, Al, As, Ba, B, Cu, Fe, Sr, V, Se), Kjeldahl nitrogen, total dissolved solids, suspended solids, turbidity, chemical

and biological oxygen demands, phenols, dissolved organic carbon, oil and grease, and radioactivity. The process waters and the deep well waters were tested for the same parameters with the addition of some elements (Ni, Cd, Mn, and Pb). Results of the monitoring program were submitted to the Water Quality Control Division on a monthly basis.

Under the new water monitoring program significant changes have taken place. The three major aspects of the new program are discussed below. Specific details of the water monitoring program are given in Appendix D of this report.

The new Subsurface Disposal Permit requires that all samples taken from the new satellite wells (UL-109, UL-110, PL-111, and PL-112) and LMB-1, and LW-101A be split, with one sample placed in refrigerated storage. In the unlikely event that the results of the first analysis show excursions, the appropriate split samples will be analyzed for the deviating parameters.

Two schedules will be used for determining sample containers and preservation techniques. For purposes of permit compliance monitoring, OOSI will abide by Bottle Schedule 1 (see Appendix D). This schedule is drawn up in accord with EPA approved methodology or, in some cases, proposed methodology that has not gained final approval. Some of these methods are inappropriate for sampling oil shale process water, therefore Bottle Schedule 2 (see Appendix D) has been prepared for in-house use. Bottle Schedule 2 has been based on the best current information available on analysis of shale oil process waters and will be used for all non-permit compliance testing of process waters. The Subsurface Disposal Permit requires the determination

of only four parameters in retort water (Li, SCN, NH_3-N and phenols). Duplicate samples will be taken and analyzed for these parameters: one set according to Bottle Schedule 1 and the other according to Bottle Schedule 2. Additional parameters of interest will be analyzed from Bottle Schedule 2 samples.

The terms of the new Subsurface Disposal Permit require reporting on a quarterly basis. Instead of submitting copies of the analytical report forms to the State as OOSI has done in the past, a data print-out from the computer for each quarter will be sent to the State. This will make it easier for the State to review the data, and OOSI will avoid sending the State information which it does not require. A schedule of the data required for the quarterly report is presented in Appendix D. The first report under the new permit will be issued in June.

(2) NPDES

A Water Monitoring Program is being carried out in compliance with NPDES Permit CO-0029947 issued to OOSI under the Federal Clean Water Act and the Colorado Water Quality Control Act. The monitoring is performed on a weekly basis whenever discharge is taking place. The water is tested for the following parameters: flow, total dissolved solids, total suspended solids, chemical and biological oxygen demands, phenols, sulfide, ammonia-nitrogen, oil and grease, fluoride, arsenic, zinc, molybdenum, copper, iron, boron, and chromium. The discharge samples are taken just below the flume in Dry Gulch (LWM001) and outside the portal to the research mine (LWM002). Discharge limitations are applicable to total suspended solids, total iron, pH, and oil and grease. The results of

the monitoring program are submitted quarterly to the State Water Quality Control Division and to the EPA Regional Administrator.

c. Method of Analysis

Water is sampled, preserved, and analyzed by approved EPA methods, when applicable, as outlined in "Methods for Chemical Analysis of Water and Wastes," "Standard Methods for the Examination of Water and Wastewater," and the "Handbook for Analytical Quality Control in Water and Wastewater Laboratories."

d. Results and Discussion

Water quality data for streams, alluvial wells, deep wells, retorts, Retort 6 wells, and NPDES discharges may be found in Appendix E of this report. Water levels data for deep wells and alluvial wells at Logan Wash also are included in Appendix E.

(1) Deep Wells and Alluvial Wells

Water levels in both deep wells and alluvial wells are recorded at the Logan Wash mining facility in an attempt to understand the natural characteristics and seasonal fluctuations which occur as part of the existing hydrology of the area. Data collected have shown uncommon fluctuations of water levels in the wells. However, due to the difficulties involved in measuring well depths, there is some question about the accuracy of these readings. This problem is being solved in the deep wells by utilizing a new method of measuring well depths developed by Geothermal Surveys, Inc. (GSI). The new method, implemented in May 1981,

consists of a conductivity probe attached to a sensor unit by a premeasured electrical cord. When the probe contacts the water surface, the sensor emits a pitched tone enabling the technician to determine the distance to the water surface.

(2) Retort Water Quality

During and after the burning of Retorts 4, 5, and 6, water samples were taken from sumps located at the product level of each retort. These samples then were analyzed for sodium, potassium, calcium sulfate, phenols, magnesium, and Kjeldahl nitrogen. Time series plots of these analyses are presented in Appendix E of this report. It was anticipated that while the retort was burning concentrations of these parameters would probably increase.

During the retort burn, sodium, sulfate, and phenols increased in Retorts 4, 5, and 6. After the retort burns were completed, the sodium concentrations decreased substantially in all retorts. Sulfate and phenol levels continued to fluctuate even after the burns were completed. Calcium, potassium, and magnesium concentrations rose during the initial startup of the retorts and then decreased again. Kjeldahl nitrogen rose significantly at the initial startup of Retort 4, but dropped substantially by the end of the burn. After the burn was completed the Kjeldahl nitrogen levels dropped even further. Kjeldahl nitrogen levels at Retort 5 did not change significantly during or after the retort burn. During the burning of Retort 6, Kjeldahl nitrogen levels rose continuously until several weeks after the burn was completed; the levels then seemed to decrease significantly.

As was expected, most parameters displayed a rapid decay of concentration levels after the retort burns were completed. Water sampling at these sites is being continued.

(3) NPDES Discharge Stations Water Quality

Water quality samples are collected weekly during discharges and analyzed for those parameters listed in Section VIII B,2,b,2. In addition, four of the parameters have effluent limitations which must be met in accordance with the NPDES permit. The parameters and effluent limitations are:

	30 Day Average	Daily Max.
Total Suspended Solids	30 mg/l	45 mg/l
Total Iron	3.5 mg/l	7.0 mg/l
pH	N/A	6-9 units
Oil and Grease	N/A	10 mg/ - no visible sheen

In the past, there have been several occasions when the limitations listed above have been exceeded. When this does occur, the Regional Administrator and the State Water Quality Control Division are notified in writing, within five days. This notification includes a description of the discharge, the cause of the problem, the period of excess, and the steps being taken to reduce, eliminate, and prevent a recurrence of the situation. Most of these experiences at Logan Wash have been with total suspended solids. Various measures, such as the construction of small settling ponds, are being taken to alleviate this problem.

Water quality data required by the NPDES permit are presented in Appendix E of this report.

(4) Streams

As part of the subsurface disposal permit for Retorts 7 and 8, baseline data on seven local streams must be collected. These streams include Roan Creek, Bowdish Creek, Logan Wash, Dry Gulch, Smith Gulch, Riley Gulch, and Parachute Creek. Water quality data collected at these streams are presented in Appendix E of this report.

3. Air Quality and Meteorology

a. Introduction

Air quality and meteorology parameters currently being monitored include suspended particulates, carbon monoxide, wind speed and direction, temperature, relative humidity, solar radiation and temperature inversion heights. Data are collected at four separate stations: the Guard Gate (LW04), the Heater Treater (LW01), the Lower Mine Bench (LW03), and the Meteorological Tower (LW02). Table XVII lists the monitoring stations, the station computer codes, the parameters measured, and the elevation above ground. Figure 43 shows an elevation profile of the Logan Wash mine area where the actual location and elevation, above mean sea level, of each station can be seen. Data covering the time period from February 1981 to April 1981 are presented in Appendix F of this report.

b. Air Quality

The long-term purpose of the Air Quality Monitoring Program has been to establish additional air quality baseline data

and to monitor any effects retorting may have on the ambient air.

(1) Suspended Particulates

Data on suspended particulates are collected through the use of a high volume sampler located at the Meteorological Tower site. When the high volume sampler is in operation, air is drawn into the sampler and through a filter by a high-flow-rate blower (40-60 ft^3/min). This allows total suspended particulates (TSP) with diameters <100 m to collect on the filter surface. The mass concentration (g/m^3) in ambient air is computed by measuring the mass of TSP collected and the volume of air sampled. This method is applicable to the measurement of the mass concentration of TSP in ambient air. Since analyses of data samples for February 1981 to April 1981 were not complete at the time of this report, the data will be included in the next quarterly report. The analyses completed showed suspended particulate values had decreased significantly. This is probably because major earth-moving activity has decreased and dust causing areas, i.e. roads, are being wetted more frequently.

(2) Carbon Monoxide

A Beckman Model 866 ambient carbon monoxide (CO) analyzer is utilized at Logan Wash to analyze and collect ambient CO data. The analyzer, located at the Heater Treater, automatically and continuously analyzes ambient air for carbon monoxide by using a differential measurement of the absorption of non-dispersed infrared energy. The instrument has been designated by the EPA as a reference method for CO monitoring in the 0 to 50 ppm concentration range. It initially was

installed in October 1980. At that time, power was being supplied by a 30 kV power generator and severe power fluctuations from the generator prevented the instrument from functioning properly. In December, commercial power was installed to the shelter containing the CO analyzer; however, due to problems with the calibration system and power being shut off to the Heater Treater site by MSHA, no valid data were collected for 1980. As soon as power is restored to the site, the CO monitor will be recalibrated and put back in line.

c. Meteorology and Climatology

(1) Wind Speed and Direction

Wind speed and direction are measured with a portable meteorological data gathering system which is mounted approximately 10 meters above ground. This station (LW01) is located at the Heater Treater plant. Quarterly wind roses were generated from the data collected at this station and are presented in Figure 46. The wind roses show the wind direction to be predominately southeast for the winter quarter and northwest for the spring and summer quarters. The spring and summer wind roses depict wind direction the same for both quarters, with wind speed slightly higher in the summer quarter. Data for September 1980 through April 1981 are unavailable for this report and will be reported in the next quarterly report to DOE.

(2) Temperature

Air temperature is measured and recorded at four locations. Due to instrument malfunctions, recorder failures, and severe weather conditions, significant

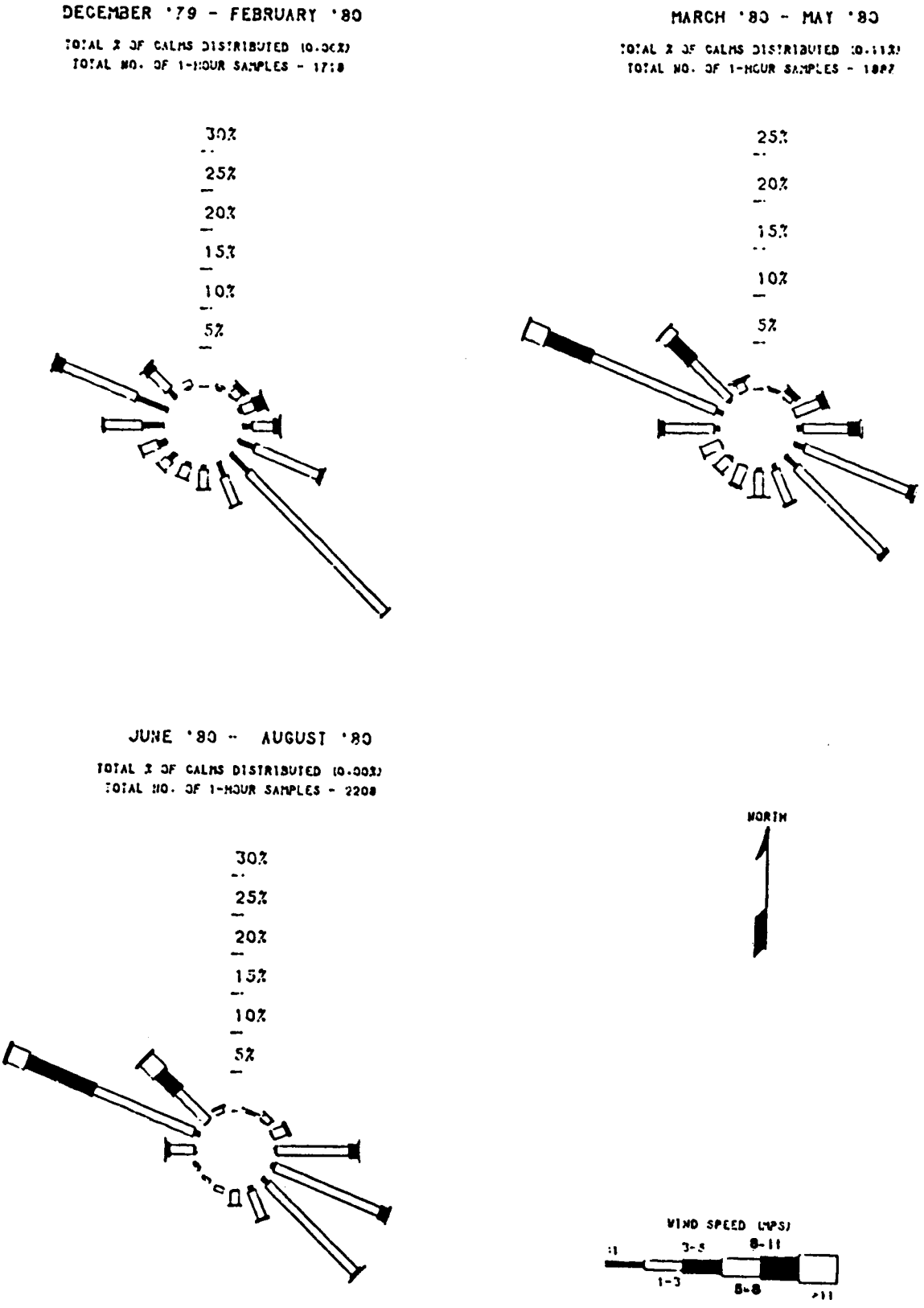


Figure 46. Logan Wash Quarterly Wind Roses, LW01.

amounts of valid data were not collected for 1980. New temperature probes will be installed at Logan Wash during the summer of 1981 in an attempt to remedy this situation. Data collected during 1980 are listed in Appendix F of this report.

(3) Relative Humidity

Relative humidity is measured and recorded by hygrothermographs which are located at the Guard Gate, the Heater Treater, and the Meteorological Tower. These instruments are positioned approximately two meters above ground. Data for February 1981 to April 1981 are presented in Appendix F of this report.

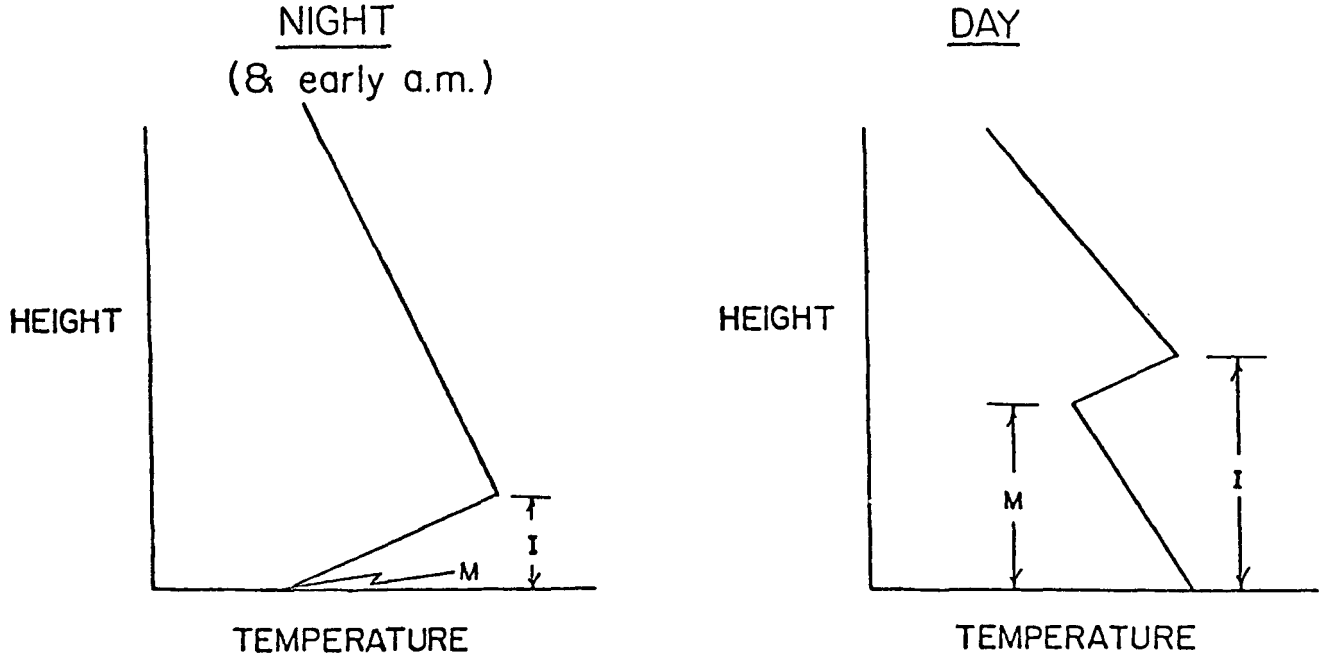
(4) Solar Radiation

Solar radiation from sun and sky is measured by a bimetallic recording pyranometer which is located at the Meteorological Tower site. Diurnal tables of data for February 1981 through April 1981 are presented in Appendix F of this report.

(5) Upper Air Studies

Temperature inversion heights are measured by means of an Acoustic Radar. The acoustic radar is located at the Heater Treater site which is 7,000 feet above mean sea level. The output of the instrument is a continuous strip chart record of reflected sound signals associated with thermal turbulence signatures. Such signatures vary in character depending on whether the atmosphere is stable or unstable. The chart provides a means for determining the height in meters of temperature inversions and mixing layers above ground level. Figure 47 gives a pictorial definition of

DEFINITIONS OF MIXING HEIGHT AND INVERSION HEIGHT



M = Mixing Height
I = Inversion (TOP) Height

Note: If $h_{(stack)} > I$ (either case) then
$M = \infty$

Figure 47. Definitions of mixing height and inversion height.

mixing and inversion heights. Due to mechanical problems with the instrument and to the fact that power was shut off at the site by MSHA, insufficient data were available to plot quarterly average and peak inversion levels.

d. Future Monitoring

Emission permits have been obtained by OOSI from the Colorado Department of Health, Air Pollution Control Division, for the operation of Modified In Situ Oil Shale Retorts 7 and 8 and associated equipment. In addition to the other parameters currently being monitored at Logan Wash, another requirement of these permits is the monitoring of ambient H_2S concentrations. Monitoring will be performed at three locations where H_2S concentrations have been predicted to be the highest; one permanent site and two remote sites which can be moved from one location to another. The permanent site, which will be at the Meteorological Tower (LW02), will utilize 110-volt line power and will be capable of monitoring H_2S, wind speed, wind direction, temperature and delta temperature. The two remote sites, see Figure 37, will monitor H_2S, wind speed, wind direction and temperature. The remote sites will obtain their power from solar panels with enclosed lead-acid batteries. Chemical batteries with several days operation capability will be utilized as a backup to the solar panels. All sites will utilize cassette recording systems for data acquisition. Routine maintenance and calibration checks will be performed by the on-site technicians. These sites will be installed at Logan Wash during the summer of 1981 and will be functional prior to ignition of Retorts 7 and 8.

4. Biology and Land Reclamation

a. Introduction

Biological surveys for the Logan Wash site began in 1974. These surveys were to identify major plant communities, major vertebrate species found in each community, and their relative abundance in these communities. Data collected are utilized to establish a data base which is used to test the null hypothesis that mining activities are not affecting the vertebrate populations. The data base also is utilized as a source of information for future comparisons of vegetation data so that effects of climatological and seasonal changes not related to mining activities may be identified.

b. Flora Surveys

As part of OOSI's environmental program, a resurvey of vegetation at the Logan Wash site was conducted during July of 1980.

During the 1974-1975 field season, 54 macroplots were located throughout OOSI property and adjacent Bureau of Land Management (BLM) lands, see Figure 48. These macroplots were combined into nine plant community types. Three macroplots were chosen from each community type for the 1977-1980 resurvey. The section of macroplots was based on comparative floristic diversity and the relative abundance of vegetal cover in the macroplot: one macroplot had the fewest species and lowest apparent vegetal cover, one had a nearly average number of species and near average vegetal cover, and the third macroplot had the greatest floristic diversity and vegetal cover available from the set of 1975 macroplots taken in a given vegetation type. In the cases where only two or three macroplots existed in a community



Figure 48. Map of Occidental Oil Shale, Inc., property with vegetation sample locations.

type, all were surveyed. The same subset of macroplots was resurveyed in July 1980 except for two macroplots, numbers 1 and 20, which could not be located due to removal of the macroplot marker stakes. This resulted in a total of 21 macroplots being resurveyed. Comparisons were made between the recent vegetation data and previous years' data.

In general, floristic diversity has shown little change, however the number of individuals has increased within the particular community. Vegetal cover in most overstory and understory vegetation has also increased. Changes of this nature are most likely due to the above normal winter precipitation experienced over the previous two years since natural fluctuations often occur in response to climatic variations. Up to the present time, mining activites seem to have had little effect on vegetation and its growth. Surface alterations resulting from tailing deposits and road-building activity are the only detectable changes incurred by the mining operation. These impacts are minimized by reclamation and revegetation of disturbed locations which are no longer being used. Reclamation activities are discussed in more detail in Section VIII,B,4,d.

c. Faunal Survey

The most recent vertebrate population study occurred in May, June, and August of 1980. The study was reported by W. O. Wirtz et al., see Appendix A of this report. Data were collected on experimental and control plots in pinyon-juniper, mountain shrub and aspen in order to test the null hypothesis that mining activities are not affecting small mammals, birds, or deer. Small mammals were studied by the mark and release technique. Birds and deer were counted visually. Experimental sites were selected in Lower and Upper Mine Gulch, within a half mile

of the mine site, see Figure 49. Control plots were established 1.5 to 2 miles from the mine site in 8605 Gulch, Upper Fall Gulch, and Northwest Riley Gulch, see Figure 49. Each site has parallel rows of stations for live-trapping studies of small mammals.

(1) Small Mammals

Large aluminum Sherman traps are used to sample small mammals. Mammals captured are weighed, a sex determination is made, and a toe is clipped for future indentification. Reproductive data are noted for all adult mammals. At least 200 trap nights are accumulated for each plot for the census period.

Small mammal abundance declined at the site between 1978 and 1980. However, this decline occurred on both experimental and control plots and did not reach the lows observed in 1977. Fluctuations in trapping success are probably related to changes in available food or other ecological parameters related to the biology of small mammals at the site, rather than to mining activities.

Deer mice are the most abundant rodent at the site, contributing 13 to 100 percent of the biomass per hectare on lower elevation sites and 28 to 95 percent of biomass per hectare on higher elevation sites. The species breeds from April to September in Colorado, and seems to fit this pattern at the Logan Wash site. Deer mice prefer the mountain shrub community at the site.

Rock mice show no clear habitat preference at the site, increasing in numbers from 1974 to 1977, and decreasing from 1978 to 1980. Breeding of rock mice

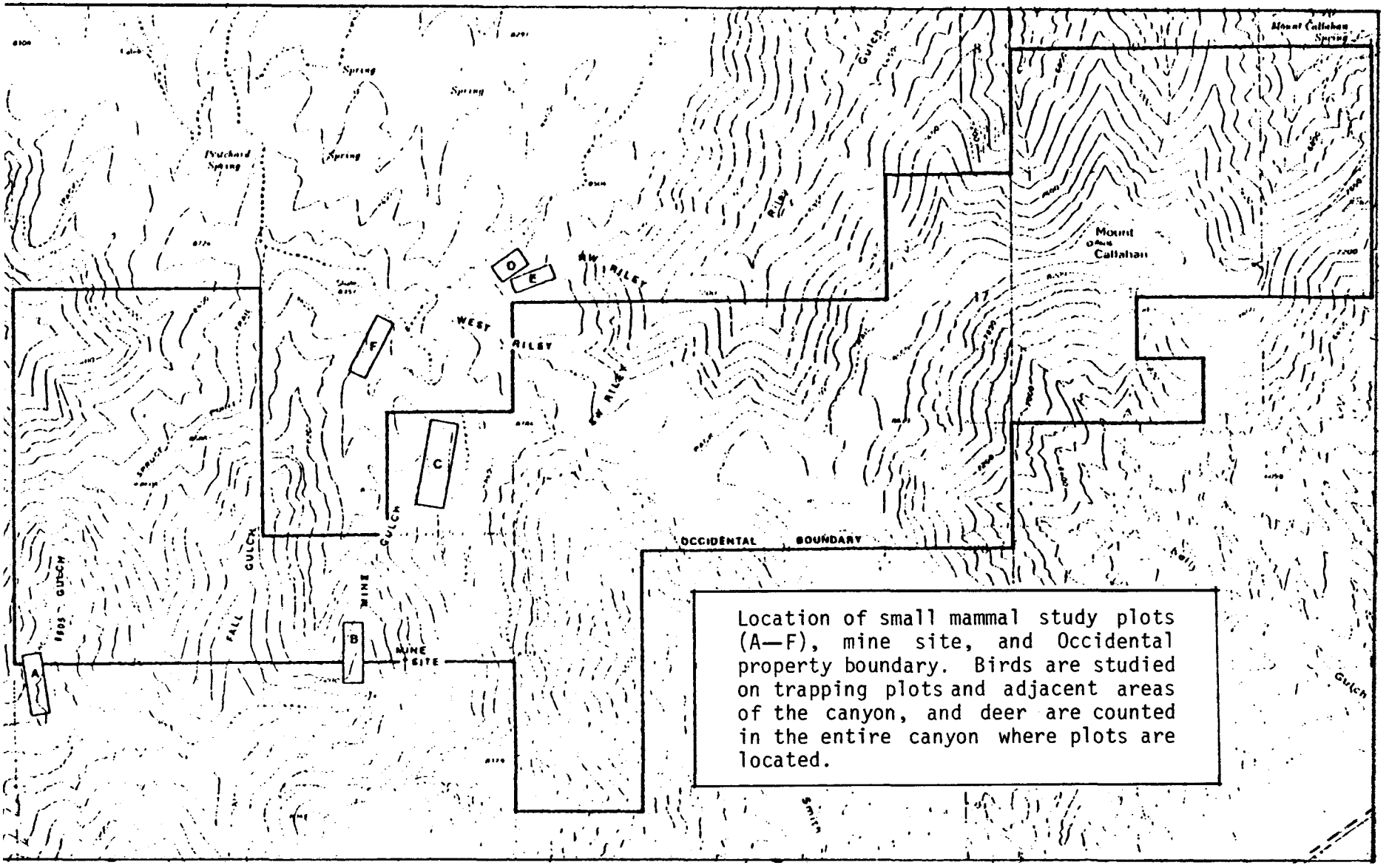


Figure 49. Location of small mammal study plots.

in Colorado is known to occur from April to August, with peak activity in May and June. The species fits this pattern at the Logan Wash site.

Pinyon mice, found chiefly in pinyon-juniper habitat, and apparently limited to this habitat by nest site and winter food requirements, increased in numbers at the site from 1974 to 1977, increased threefold in abundance in 8605 Gulch between August 1977 and August 1978, and decreased sharply in abundance between 1978 and 1980. The species breeds from June through September in southwestern Colorado and appears to follow this pattern at the Logan Wash site.

Chipmunk and golden-mantled ground squirrel populations have remained relatively constant during the present study, comprising 8 to 15 percent of captures at lower elevations and 5 to 28 percent of captures at higher elevations. Breeding of the least chipmunk at the site fits the pattern reported by Wirtz et al. 1980. No evidence of reproduction in the Colorado chipmunk has been noted at the site since 1974. Golden-mantled ground squirrels produce a single litter in early spring in Colorado. Young have been taken at the Logan Wash site in May.

Ecological comparison may be made between study sites on the basis of the biomass contributed per hectare by each species of rodent. An inspection of biomass curves for higher elevation sites, see Figure 50, lends strong support for the null hypothesis. Though there are no major differences between control and experimental sites, the curves for each species are very similar in form for both sites. This lends strong support not only for the null hypothesis, but also for the hypothesis that fluctuations in population

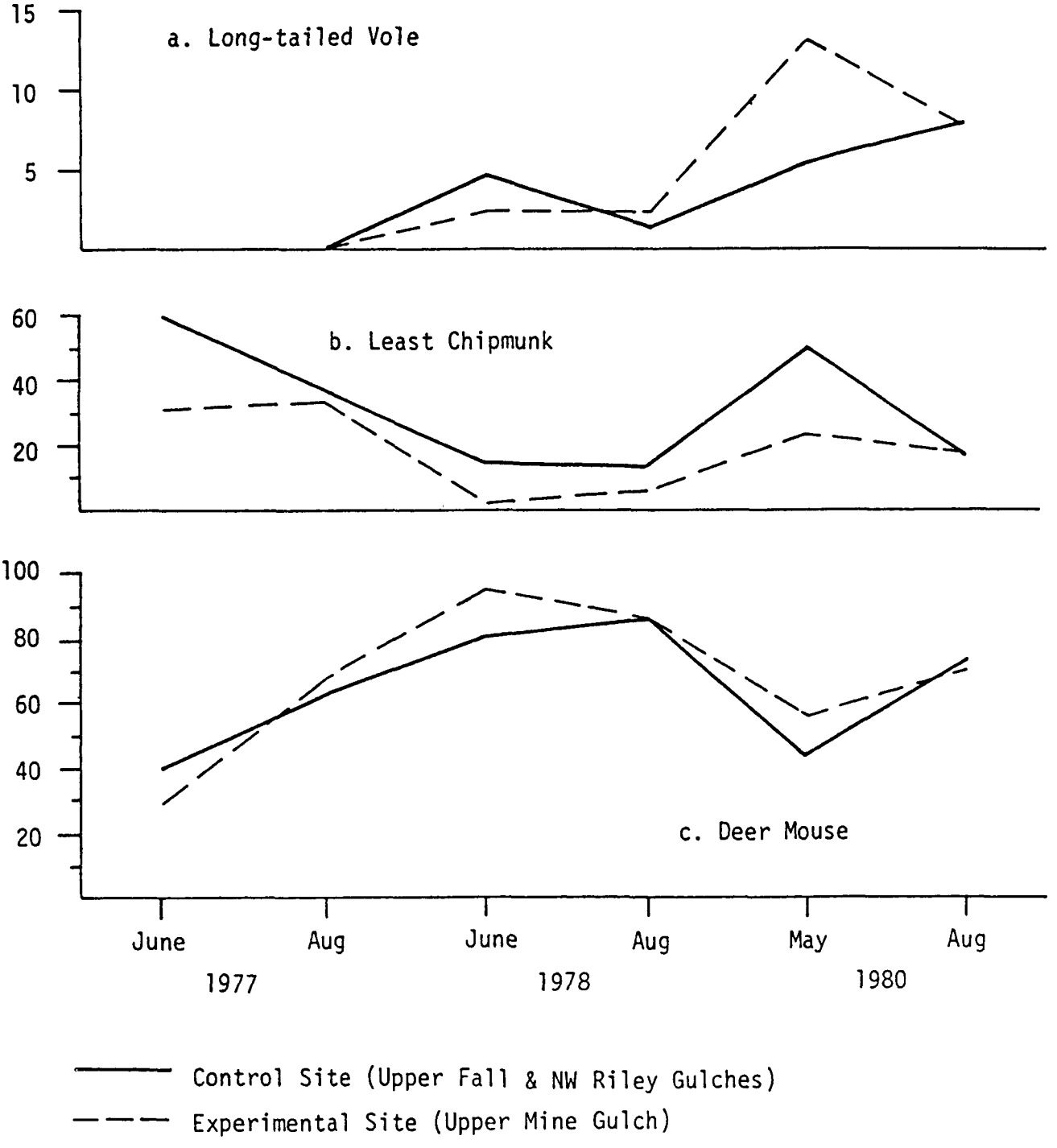


Figure 50. Biomass of rodents on control and experimental sites at higher elevations, per cent of total grams per hectare.

numbers, and therefore biomass, are governed by some extrinsic factor, such as weather, rather than by proximity to mining activity.

At lower elevations, biomass on the control site has remained similar throughout the study, exhibiting spring to fall increases, except in 1980, see Figure 51. The decline in August is presumed to be due to the absence of and decrease in the total catch of larger species, such as woodrats, ground squirrels, and chipmunks. The large increase in biomass on the lower elevation experimental site is primarily due to an increase in numbers of deer mice. This increase may be due to the fact that mining operations are making the area more suitable for deer mice and perhaps less suited for other species.

With three years of data, it is possible to examine several parameters of rodent demography for possible effects of mining activity at the Logan Wash site. Percent trap success has been similar at lower and higher elevations during these years. Fluctuations from year to year at both lower and higher elevations have been similar, suggesting extrinsic factors, such as weather, as the cause of rodent density fluctuations. Population density and diversity indices have fluctuated from year to year, season to season, and between control and experimental plots, see Figure 52. These variations suggest that populations are responding to natural environmental variation and leading to the conclusion that, at present, there is no evidence that proximity to mining activities is having a detrimental impact on small mammal populations.

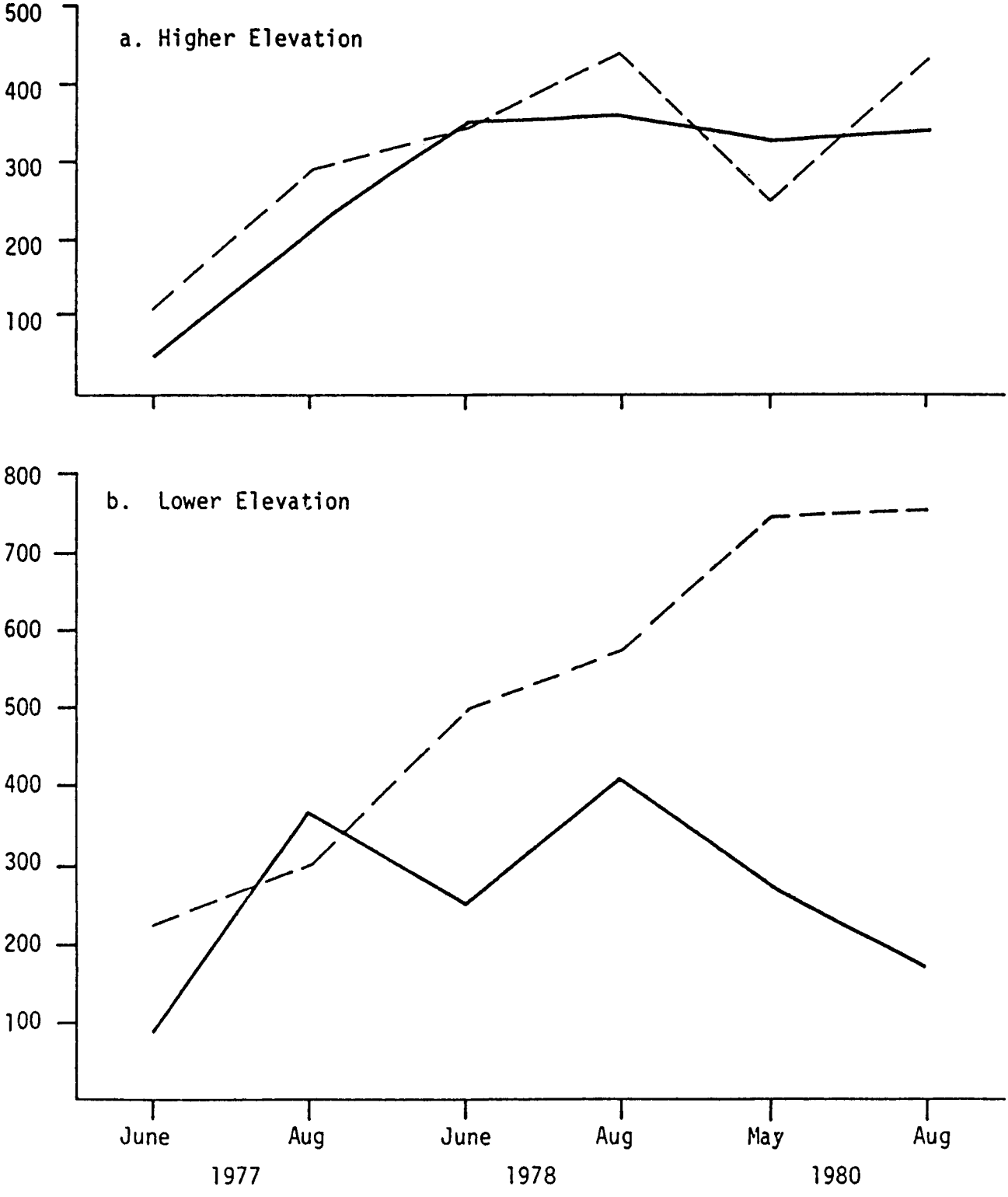


Figure 51. Biomass of rodents at higher and lower elevations, control and experimental plots.

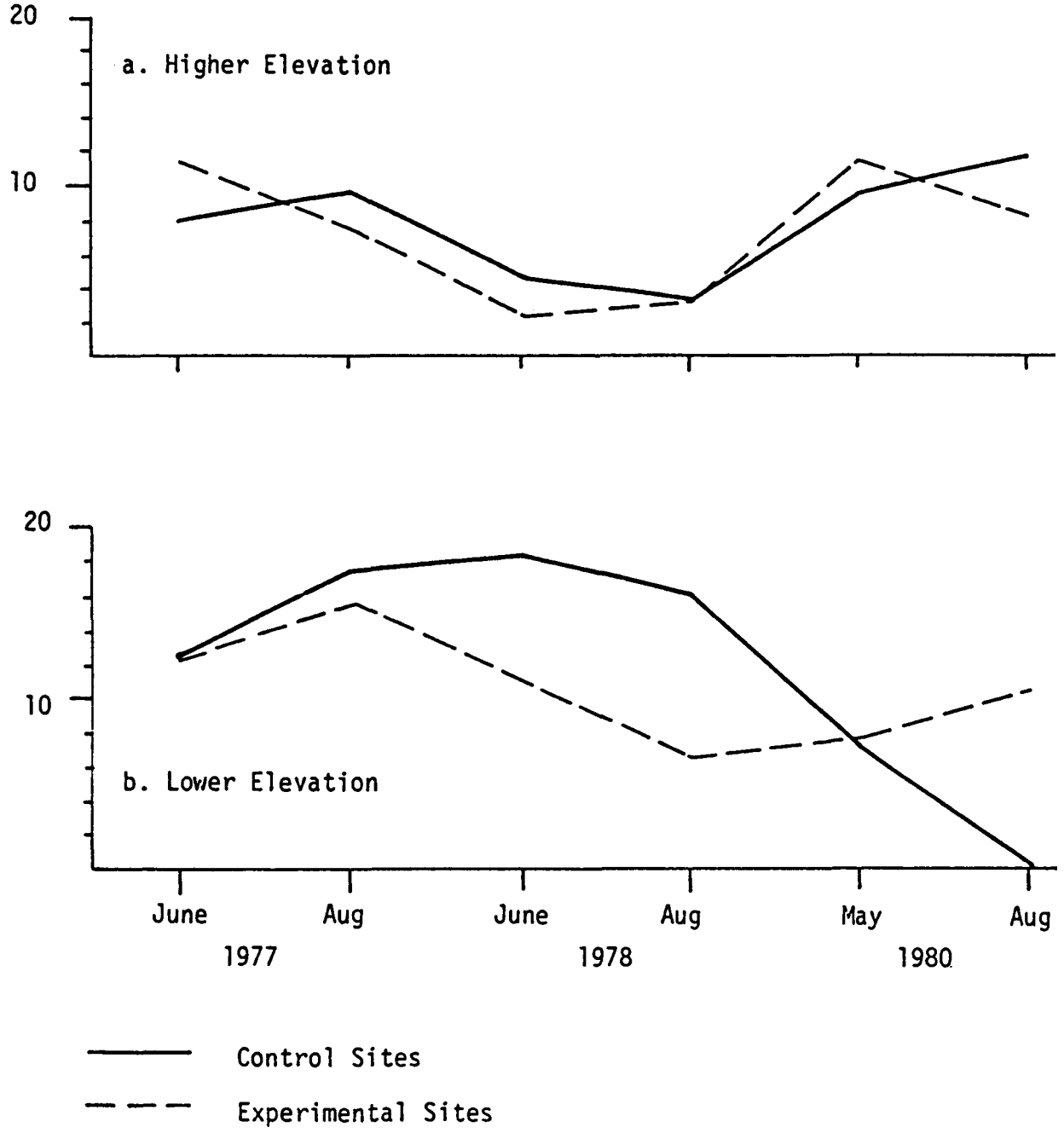


Figure 52. Rodent diversity at higher and lower elevations, control and experimental plots.

(2) Birds

Detailed information is collected on birds in the trapping plots and adjacent areas of the canyon. A running tally is kept of all birds seen on each pass through a study plot. Attempts are made to count early in the morning when bird activity is the greatest. Counts also are made during the day and in the evening. Comparisons are possible between study plots on the basis of individuals per species per man-hour of observation.

In 1980, only 23 species were represented in the major percentage of the sightings at the Logan Wash site, but field data indicate that as many as 35 species could have bred there. Data for 1974 and 1977 suggested that 33 species were of particular importance at the site. In 1978, only 27 species were accounted for in a major percentage of the sightings and/or were known to breed there.

Inspection of all bird data for the Logan Wash site indicates that 20 species are of major importance. Three species are common at both higher and lower elevation sites: the white-throated swift, the broad-tailed hummingbird, and MacFillibray's warbler. Six species are common only at lower elevations: the violet-green swallow, the scrub jay, the blue-gray gnatcatcher, Virginia's warbler, the black-throated gray warbler, and the rufous-sided towhee. Eleven species are common only at higher elevations: the American kestrel, the common flicker, the dusky flycatcher, the black-capped chickadee, the house wren, the robin, the mountain bluebird, the warbling vireo, Audubon's warbler, the green-tailed towhee, and the gray-headed junco. The nine species common at lower elevation

sites contribute 40 to 78 percent of all sightings on the control, and 61 to 91 percent of all sightings on the experimental plot. The 14 species common at higher elevation sites contribute 47 to 93 percent of all sightings on control, and 59 to 93 percent of all sightings on the experimental sites.

Patterns of abundance for common species are similar for control and experimental sites at both higher and lower elevations. These data suggest that abundance is a function of some extrinsic factor such as weather, and tend to support the null hypothesis that mining activities are not having an adverse effect on avian populations.

Avian diversity indices are similar on both control and experimental sites at higher elevations. At lower elevations, diversity is lower on the experimental sites. This may be a reflection of the impact of mining activities, or it may reflect habitat differences between experimental and control sites. Data on avian diversity at both higher and lower elevations tend to support the null hypothesis that mining activities are not having an effect on avian populations at the Logan Wash site.

(3) Deer

The mule deer census is taken carefully in the canyons where plots are located. The deer are observed at dawn and dusk, and records are kept of all deer seen at the site. Spotting scopes are used to determine age and sex of as many animals as possible. Tallies of the same canyon by different observers and of the same canyon for different days are carefully analyzed

to arrive at the maximum number of different individuals on a given study plot. This number is considerably lower than the total number of sightings over a several day period.

Only 35 deer were seen at the site in May and June 1980, while 252 were seen in August 1980, see Table XIX. These figures include repeat sightings. The 252 deer observed at the site in August 1980 are believed to represent 86 different individuals, distributed as indicated in Table XIX. Not all of the site was included in the census and so this number does not represent a population estimate for the entire site.

A comparison of census data for 1977, 1978, and 1980, see Figure 53, suggests a slight decrease in the size of the resident herd since 1978. The female proportion of the population has not changed since 1977, the male proportion has increased slightly, and the fawn proportion has decreased slightly. The buck to doe ratio at the site has remained below 1:2 since 1978 which is considerably better than the average of 1:3.34 reported by Wirtz et al. 1980. The calculated fetal rate for breeding does at the site was slightly lower than the 1.38 determined in 1978 and the 1.42 determined in 1977. These rates are all lower than the 1.67 average reported for does two to seven years old in Utah, according to Wirtz et al. 1980.

The decrease in the number of deer observed at the site and the number estimated to be resident on study areas between 1978 and 1980 is most likely a result of the severe winter in 1978-79, and not related to mining activity or other human perturbation. The lower number of deer seen at the site in late May and

TABLE XIX

DISTRIBUTION OF THE ESTIMATED DEER POPULATION ON STUDY PLOTS

Logan Wash Site - August 1980

	Male	Female	Fawn	Total
8605	0	1	1	2
Lower Fall	1	0	0	1
Lower Mine	4	3	3	10
Upper Mine	10	7	4	21
Upper Riley	6	11	5	22
Upper Fall	4	9	5	18
Other	1	5	6	12
TOTAL	26	36	24	86

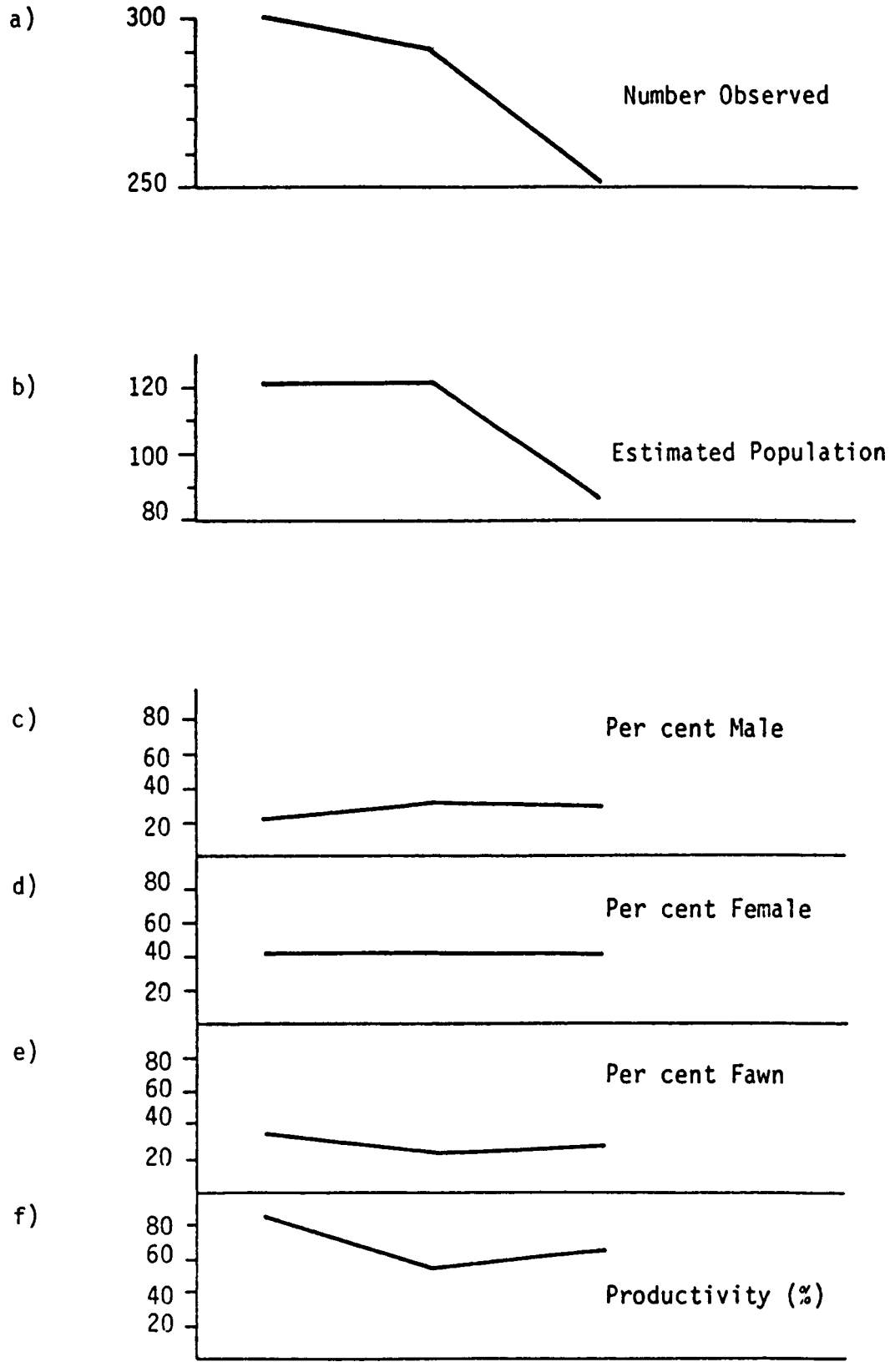


Figure 53. Mule deer demography at the Logan Wash site.

early June 1980 is attributed to the fact that most deer had not yet moved to higher elevations. Aspen and most shrubs were just beginning to leaf out in late May, and therefore neither food nor shelter was available for the deer at this time.

Also observed in 1980 was an apparent shift in habitat preference. Data from previous years have shown a clear preference by mule deer for the mountain shrub community at higher elevations. However, in August 1980 there was heavy utilization of aspen by mule deer in Upper Riley, Upper Fall, and on the east end of the mesa. There is no obvious explanation for this apparent shift, and no special significance is attributed at this time. Should the shift persist in future years, studies on diet and forage nutrient levels might be useful in the search for an explanation.

(4) Other Vertebrates

In addition to the species for which quantitative data are presented above, three lizard species and nine additional species of mammals were noted at the site in 1980. Eastern fence lizards were observed in low densities in pinyon-juniper, horned lizards occurred in very low densities on top of the mesa, and plateau whiptail lizards were extremely rare in pinyon-juniper.

Desert cottontail rabbits were observed at low densities at lower elevations, and white-tailed jackrabbits were rare at higher elevations. Rock squirrels were observed at low densities at lower elevations. Yellow-bellied marmots were rare in aspen groves at higher elevations. Single porcupines were

observed in Lower Fall and Upper Fall. These are the first summer records for the site by this project. Coyotes were very rare at the site; none were seen, and only vocalizations and a few tracks provided record of presence. Both short-tailed and long-tailed weasels were observed at higher elevations. Miners reportedly observed a female mountain lion and her kitten in Logan Wash; this report has not been verified by the principal investigator.

Four bull elk were utilizing West Riley in August. These are the first sight records by this project for the Logan Wash site, though tracks have been found on top of the mesa in other years. Cattle were in abundance on the site in August with more observed than previously seen by this project. A high count of 96 animals was made in Upper Fall and lesser numbers were observed in Northwest and West Riley. There was heavy impact on vegetation around water sources in Upper Fall, West Riley, and Northwest Riley. Trampling of vegetation was severe around the water tanks in Upper Fall and West Riley, and in the aspen of Northwest Riley. At the latter site virtually all the herbaceous vegetation beneath the aspen was destroyed by August 14.

d. Reclamation

The reclamation at Logan Wash is governed by the Mined Land Reclamation Permit submitted by OOSI in February of 1978. This permit stipulates the procedures necessary to guarantee the revegetation of all abandoned locations at the Logan Wash site. Table XX lists and describes all areas disturbed and revegetated before and during 1980. These areas are depicted on the maps shown in Figure 54 in the folder at the back of this report.

TABLE XX
ESTIMATES OF ACREAGES DISTURBED AND REVEGETATED [1]

AREA NO.	DESCRIPTION[2]	ACREAGES DISTURBED[3] BEFORE 1980	ACREAGES DISTURBED[3] DURING 1980	ACREAGES REVEGETATED[4] BEFORE 1980	ACREAGES REVEGETATED[4] DURING 1980
1	Main entrance facility, parking area, maintenance area, buildings, heliport	5.00	4.00		
2	Upper and lower mine portal and bench, research mine bench, commercial and research mine dumps and buildings	42.00	9.00		
3	Overflow ponds and buildings, runoff erosion control	8.00	1.00		
4	Surface control facility buildings, drill pads, exhaust stack, raise bore, ventilation fan, site and power substation and communication facilities	8.00	2.00		
5	Heater-Treater plant	3.00	<1.00		
6	Road Maintenance area	<1.00			
7	Road maintenance area	<1.00			
8	Road maintenance area	<1.00			
9	Meterological Tower	1.00			
10	Surface road widening	11.00	5.00		
11	Main access road--disturbed prior to this mining facility--55.55		6.00		
B-1	Realignment of existing access road	1.00			1.00
B-2	Realignment of existing access road	1.00			<1.00
B-3	Realignment of existing access road	<1.00			<1.00
B-4	Realignment of existing access road	<1.00			
B-5	Realignment of existing access road	<1.00			
B-6	Buried power cable corridor to Met. Tower		2.00		2.00
B-7	Realignment of existing access road (0.33 acres included in Area 10 total acreage)				
	TOTAL	83.00	28.00		5.00

[1] Acreages revised from 1979 Annual Report based on aerial photos taken 1980.
[2] Numerated disturbed areas in column correspond to numerated areas at Logan Wash - Disturbed Area Maps LWR 1 and 2
[3] Total acreages disturbed to date = 112.00
[4] Total acreages revegetated to date = 5.00

The Logan Wash access road realignment areas which were seeded during October of 1980 included B1, B2, and B3. A corridor for the burying of a powerline used to install commercial power to the Meteorological Tower in September 1980 was seeded in November 1980, see Figure 54 in the folder at the back of this report.

Areas revegetated in the fall of 1980 were hydroseeded using grass fiber mulch, see Table XXI. The mulching rate was approximately 2,000 lbs/acre. Due to competition from weeds, areas are not fertilized until after two growing seasons. Therefore, the areas revegetated in the fall of 1980 (B1, B2, B3 and the Meteorological Tower access road) will be fertilized in 1982.

5. Photography

During the summer of 1975, a series of photographic map stations were established as depicted on Figure 37. From these map stations, a 360-degree photographic pan is taken each year during the growing season. The visual record is being accumulated in order to observe potential long-term ecological changes with time. To date, the photo record does not reveal any short-term changes.

The last photo survey was conducted in August of 1980. The four 360° mosaics (horizontal pans) from points 6, 15, 20, and 24 were included in the December 1980 quarterly report. Photo point 20, which produced the most striking mosaic, also is presented in this report, see Figure 55 in the folder at the back of this report.

6. Quality Assurance

The main objective of the quality assurance program is to improve or assure the quality of measured data. By implementing an effective quality assurance program OOSI can establish and

TABLE XXI
SPECIES LIST FOR LOGAN WASH RESEEDING AND MULCHING

Species		Lbs/Acre
Agropyron cristatum	Crested wheatgrass	2
A. Smithii (rosana)	Western wheatgrass	2
Agropyron trachycaulum	Slender wheatgrass	2
A. intermedium (amur)	Intermediate wheatgrass	2
Bromus marginatus	Mountain brome	2
Elymus junceus	Russian wildrye	2
Festuca ovina	Hard sheep fescue	2
Oryzopsis hymenoides	Indian ricegrass	2

The above species listed were pure live seed.

Mulch

Jacklin Organic Mulch (grass fiber) was used at a rate of 2,000 lbs/acre.

assess comparability of data quality entering the data base. In the fall of 1980 a revised quality assurance program for hydrology and water quality was implemented. The revised program was aimed at improving documentation, providing uniformity of procedures, and training personnel. A revised quality assurance document for air monitoring and meteorology currently is being written. The revised manual will include procedures for sampling, calibration, maintenance, data collection, auditing, documentation, and reporting.

IX. MARKETING STUDIES

The DOE/OOSI marketing studies are a part of an overall program being developed for shale oil processing, transport and marketing. An outline of the program is given in Appendix G, of the Quarterly Progress Report for the period June through August 1980.

A report which builds upon earlier work has been produced under the marketing studies program in Phase II of the Cooperative Agreement and is given in Appendix E of the Quarterly Progress Report for the period September through November 1980. It is titled "Preliminary Investigation for Transportation of Shale Oil by Pipeline, Phase I: State-of-the Art Literature Search," Williams Brothers Engineering Company, September 1980. The report was assembled to provide a data base for subsequent laboratory testing programs and feasibility studies of shale oil transportation, and presents a number of pipelining alternatives for consideration.

Following the literature search, Williams Brothers proceeded with Phase II, investigation of shale oil rheology, and Phase III, a conceptual pipeline design, of their marketing study for OOSI.

The rheology investigations include pour points and the effects of temperature on viscosity, enthalpy and density. The work includes the properties of raw shale oil and a preliminary study of the effects of additives in lowering pour points and viscosities. Further tests on the use of additives are recommended since the preliminary work is inconclusive.

A conceptual pipeline design is given to transport 100,000 barrels per day (bpd) of raw shale oil east over the Rocky Mountains, some 260 miles. The cost of the pipeline compares favorably with that of truck or rail transportation. The pipeline is designed to handle the high viscosities and pour point of the shale oil.

The report on this work, Pipeline Transportation of Shale Oil, Phase II: Shale Oil Rheology, Phase III: Pipeline Conceptual Design, Williams Brothers Engineering Company, February 1981, is in Appendix G of this report.

A second study, performed by the Pace Company Consultants and Engineers, Inc., assesses the technical, economic, and logistical factors involved with the utilization of shale oil. Both specific and general key issues which will effect the introduction of shale oil into the U.S. refining system are brought out. A production forecast is given and outlooks for marketing, transportation, refining and economics are discussed. The report on the Pace study, Overview of Shale Oil Development and Utilization, November 1980, is included in Appendix H of this report.

X. SCHEDULE

Throughout this second year of the Phase II reporting period most activities remained on schedule. Access drifting was completed and major construction and drilling activities continued as scheduled. The MR3 startup tests were rescheduled from August to October and then to November because of hook-up and shakedown work needed. MR4 tracer testing continued into September. MR4 ignition was updated to January 1981 with plans to rubble R8X after processing MR4. R8X and R7 were detonated as planned, but R8 detonation was delayed one week because of the amount of cleanup required after the R7 detonation. The MR4 inert gas generator ignition test progressed smoothly. The overall schedule has remained unaffected by the ignition retest of MR3 in late April and early May.

Milestones for Phase II in Exhibit A to Appendix C of the Cooperative Agreement were changed in November 1980. An updated 1981-82 budget and schedule were presented to DOE/LETC in January 1981. Both the milestones and schedule are included in this report as Table XXII.

TABLE XXII
MOD. AO11 PHASE II MILESTONE SCHEDULE

1.	Commence Phase II	June 1, 1979
2.	Ignite Mini-Retort 3	September 1980
3.	Final Design for Retorts 7 & 8	October 1980
4.	Ignite Mini-Retort 4	March 1981
5.	Rubble plus Cleanup of Retorts 7, 8 & 8X	October 1980-January 1981
6.	Start Diagnostic Tests of Retorts 7 & 8	June 1981
7.	Complete Retort 7 & 8 Startup Plan	June 1981
8.	Estimate Minimum Success Criteria	September 1981
9.	Ignite Retorts 7 & 8	September 1981
10.	Shutdown of Retorts 7 & 8	April 1982
11.	End of Phase II	July 1982
12.	Submit Final Report	October 1982

XI. PLANS FOR THE COMING YEAR

The major activities planned for Retort 7 and 8 are:

- Complete bulkhead, piping and electrical construction
- Complete thermocouple installation
- Complete instrumentation
- Tracer test R7 and 8
- Ignite R7 and 8 in the fall of 1981 and begin processing

XII. APPENDICES

APPENDIX A

Report Listing

LIST OF PHASE II PROGRESS REPORTS AVAILABLE THROUGH THE DEPARTMENT OF ENERGY, TECHNICAL INFORMATION CENTER

PHASE II REPORT	
1st Quarterly	Occidental Vertical Modified In Situ Process for the Recovery of Oil from Oil Shale, Phase II, Quarterly Progress Report for the Period June 1, 1979 through August 31, 1979, October 1979.
2nd Quarterly	Occidental Vertical Modified In Situ Process for the Recovery of Oil from Oil Shale, Phase II, Quarterly Progress Report for the Period September 1, 1979 through November 30, 1979, December 1979.
3rd Quarterly	Occidental Vertical Modified In Situ Process for the Recovery of Oil from Oil Shale, Phase II, Quarterly Progress Report for the Period December 1, 1979 through February 29, 1980, March 1980.
1st Annual	Occidental Vertical Modified In Situ Process for the Recovery of Oil from Oil Shale, Phase II, Annual Progress Report for the Period June 1, 1979 through May 31, 1980, August 1980.
4th Quarterly	Occidental Vertical Modified In Situ Process for the Recovery of Oil from Oil Shale, Phase II, Quarterly Progress Report for the Period June 1, 1980 through August 31, 1980, September 1980.
5th Quarterly	Occidental Vertical Modified In Situ Process for the Recovery of Oil from Oil Shale, Phase II, Quarterly Progress Report for the Period September 1, 1980 through November 30, 1980, January 1981.
6th Quarterly	Occidental Vertical Modified In Situ Process for the Recovery of Oil from Oil Shale, Phase II, Quarterly Progress Report for the Period December 1, 1980 through February 28, 1981, May 1981.

ENVIRONMENTAL REPORTS

Classification		Report	DOE Source
Biology	1.	N.E.West and J.R.Irvine, Appendix H to An Ecological Baseline Study of Flora, Vegetation, and Soils on the Occidental Oil Shale, Inc., Logan Wash Site Near DeBeque, Colorado, Vegetation Data and Analysis for September 1979, Occidental Oil Shale, Inc., Grand Junction, CO (November 1979).	2nd Quarterly
	2.	W.O.Wirtz,II, Small Mammal Populations in Colorado Oil Shale Country, 60th Annual Meeting, American Society of Mammalogists, University of Rhode Island, Providence, RI, (8-12 June 1980).	1st Annual
	3.	N.E.West and J.R.Irvine, Appendix I to An Ecological Baseline Study of Flora, Vegetation, and Soils on the Occidental Oil Shale, Inc., Logan Wash Site Near DeBeque, Colorado, Vegetation Data and Analysis for September 1980, (prepared for Occidental Oil Shale, Inc., Grand Junction, CO) (November 1980).	5th Quarterly
	4.	W.O.Wirtz,II, and J.S.Brown, Vertebrate Populations at the Occidental Oil Shale, Inc., Logan Wash Site, Summer 1980, (November 1980) (prepared for Occidental Oil Shale, Inc., Grand Junction, CO).	5th Quarterly
Hydrology and Water Resources	5.	Coors Labs Water Quality Analysis, Coors/Spectro-Chemical Laboratory, Golden, CO (September and October 1979) (prepared for Occidental Oil Shale, Inc., Grand Junction, CO).	2nd Quarterly
	6.	Logan Wash Tract Water Analysis, January 1, 1980, through February 15, 1980, Alluvial Wells, Surface Sites, Bedrock Wells, Mine Water, and Process Water, Occidental Oil Shale, Inc., Grand Junction, CO.	3rd Quarterly

ENVIRONMENTAL REPORTS

Classification		Report	DOE Source
Hydrology and Water Resources (continued)	7.	C.S.Stover and D.Rogers, Results of Logan Wash Water Quality Monitoring Program for Retort 6, Occidental Oil Shale, Inc., Grand Junction, CO, (March 10, 1980).	1st Annual
	8.	Logan Wash Tract Water Analysis, March 13, 1980, through May 8, 1980, Surface Sites, Alluvial Wells, Bedrock Wells, Mine Water, and Process Water, Occidental Oil Shale, Inc., Grand Junction, CO, (June 9, 1980).	1st Annual
	9.	Air Quality and Water Quality Data, Occidental Oil Shale, Inc., Grand Junction, CO.	4th Quarterly
	10.	Site Water Analysis, Occidental Oil Shale, Inc., Grand Junction, CO.	4th Quarterly
Meteorology, Air Quality, and Gaseous Emissions	11.	Air Quality and Water Quality Data, Occidental Oil Shale, Inc., Grand Junction, CO.	4th Quarterly
Permit Status	12.	Logan Wash Permit Status, Compiled February 29, 1980, Occidental Oil Shale, Inc., Grand Junction, CO.	3rd Quarterly
	13.	Logan Wash Permit Status, Compiled August 7, 1980, Occidental Oil Shale, Inc., Grand Junction, CO.	4th Quarterly
	14.	Logan Wash Permit Status, Compiled February 9, 1981, Occidental Oil Shale, Inc., Grand Junction, CO.	6th Quarterly
General	15.	Environmental Data, May, June and July 1979, Occidental Oil Shale, Inc., Grand Junction, CO.	1st Quarterly

ENVIRONMENTAL REPORTS

Classification		Report	DOE Source
General (continued)	16.	Environmental Data, August, September, and October 1979, Occidental Oil Shale, Inc., Grand Junction, CO.	2nd Quarterly
	17.	Environmental Data, November and December 1979, and January 1980, Occidental Oil Shale, Inc., Grand Junction, CO.	3rd Quarterly
	18.	Environmental Data Analyses, Occidental Oil Shale, Inc., Grand Junction, CO (1979-80).	1st Annual
	19.	Environmental Data, Data Not Previously Reported in Quarterly Reports, Occidental Oil Shale, Inc., Grand Junction, CO.	5th Quarterly
	20.	Environmental Data, Occidental Oil Shale, Inc., Grand Junction, CO (1980).	6th Quarterly

MARKETING REPORTS

1.	Engineering Program for Market Evaluations Including Upgrading and Logistics, Occidental Oil Shale, Inc., Grand Junction, CO.	4th Quarterly
2.	Pipeline Transportation of Shale Oil, Phase I: State-of-the-Art Literature Search, Williams Brothers Engineering Company, Resource Sciences Center, Tulsa, Oklahoma (September 30, 1980) (prepared for Occidental Oil Shale, Inc., Grand Junction, CO).	5th Quarterly

MINE STABILITY REPORTS

1.	F.G.Horino, USBM Mine Stability Correspondence, May 1977 through May 1979, Mine Structure Design, Denver Mining Research Center (written to I.G.Studebaker, Occidental Oil Shale, Inc., Grand Junction, CO).	4th Quarterly

ITEM	DOE Source
MINI-RETORT DATA	
MR4 Start Up Data	6th Quarterly
RETORTS 7 AND 8 DATA	
Core Analysis	
Core Analysis (Core Hole LW-156)	5th Quarterly
BuMines RI 7357, Appendix B, Lithologic Descriptions	5th Quarterly
Core Analysis	6th Quarterly
Instrumentation	
G.P.Gruber, et al., DOE/OOSI Cooperative Agreement Phase II Instrumentation Plan, Occidental Oil Shale, Inc., Grand Junction, CO (1980).	4th Quarterly
Sampling and Analyses Program	6th Quarterly
Thermocouple and Sample Tap Plan	6th Quarterly

APPENDIX B

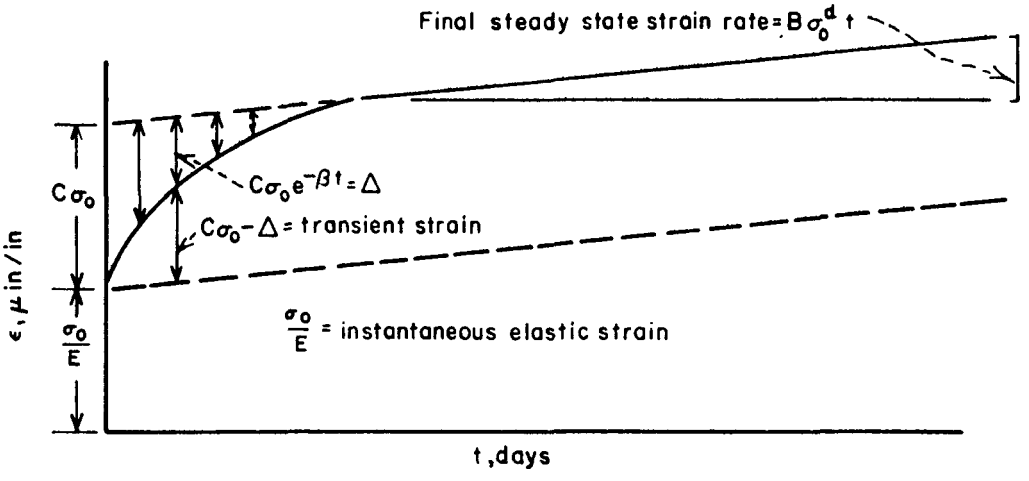
USBM Mechanical Properties Report

DENVER RESEARCH CENTER

Progress Report 10025

Mechanical Properties, In Situ Stress and Temperature Measurements — Logan Wash Oil Shale Site

NOT FOR PUBLICATION - FOR OFFICIAL USE ONLY



DEPT. OF THE INTERIOR - BUREAU OF MINES
GALEN G. WADDELL
RESEARCH DIRECTOR, DRC

MECHANICAL PROPERTIES, IN SITU STRESS AND TEMPERATURE MEASUREMENTS- LOGAN WASH OIL SHALE SITE

by

Frank G. Horino[1]

Dennis R. Dolinar[2]

David L. Bickel[3]

Purpose of Report

Progress report of cooperative research between Occidental Oil Shale, Inc. and the United States Bureau of Mines to obtain rock mechanics data for use in mine design and for stability evaluation of modified in situ retorts. Results of the report will be incorporated into a Bureau of Mines Report of Investigations at a later date.

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ABSTRACT

A combined effort was made by the U.S. Bureau of Mines and Occidental Oil Shale, Inc., through a cooperative agreement to determine very necessary information on the pioneer effort involving in situ oil shale retorts. Three phases of this effort are presented here and these are: 1) Mechanical properties, 2) In situ stress measurements, and 3) Temperature measurements.

Phase 1 effort produced the following results:

1) Using linear regressions analyses, predictive equations were produced relating yield in gallons per ton (gpt) to compressive strength, apparent specific gravity, Young's modulus, and Poisson's ratio for the Mahogany zone.

2) Creep studies showed that closure should not be a problem in the air room.

3) A compaction rate of 2½% was measured on in situ retorted oil shale blocks which had a compressive strength value averaging 992 psi.

4) Tests conducted on oil shale samples that were ground, sized, and lab-retorted indicated that for the same particle size and for a given load, the compaction is greater for the shale with the greater yield.

5) For this lab-retorted oil shale with the same yield, the larger the particle size, the greater will be the compaction for a given load.

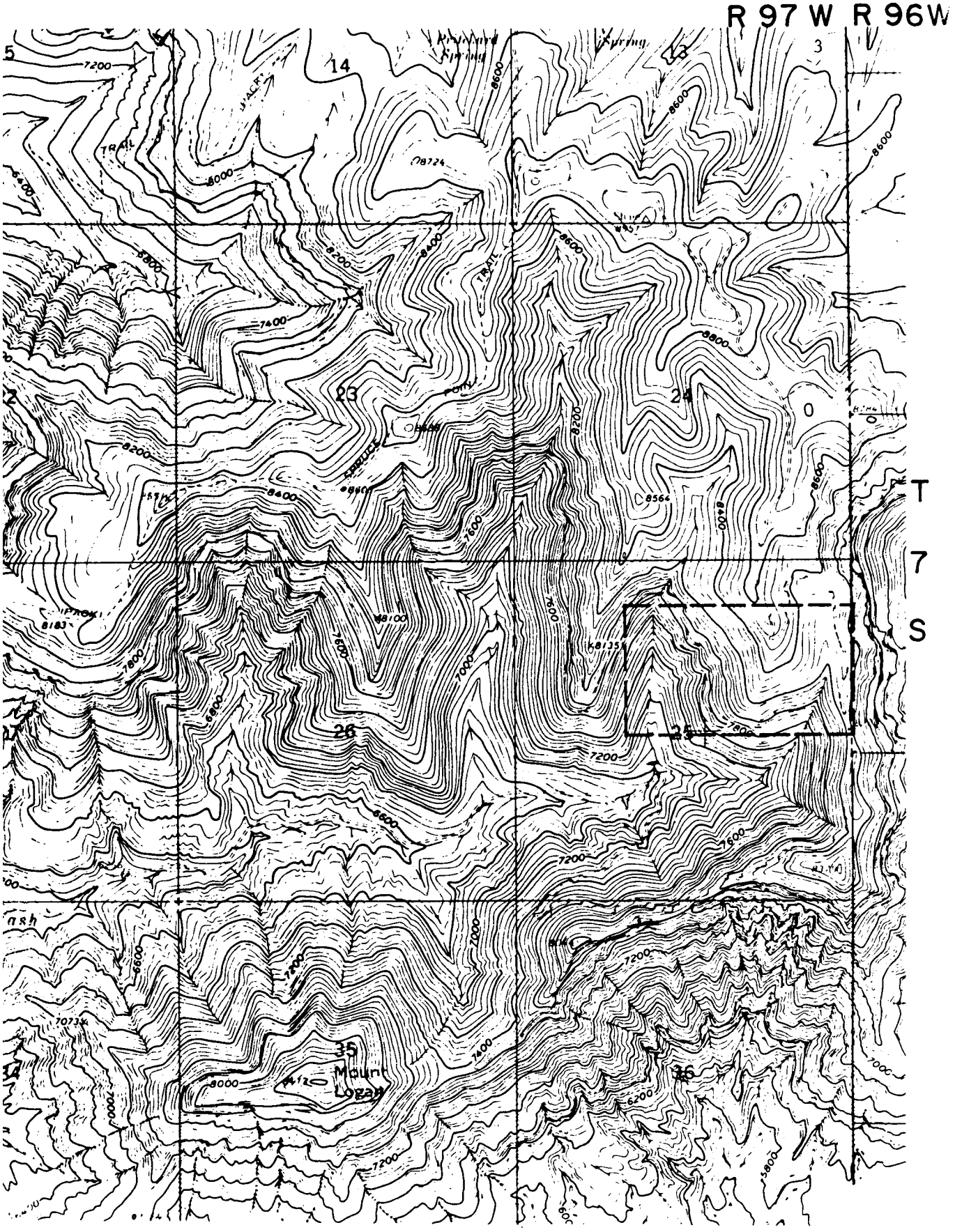
Modulus-of-rupture tests with end-loading indicate a 1250 psi strength increase with each end-pressure increase of 500 psi. A value for the modulus of rupture for a roof horizon equal to twice the indirect tensile strength was determined to be fair first approximation.

In phase 2 of the program the complete 3-dimensional state of stress was determined on the upper air room level. These measurements indicate that the stress field is primarily gravity induced with little or no tectonic stresses. In situ stress measurements were also made in various retort structures of retort No. 6 to determine the effects of rubblization on the stresses and stress distribution. The largest change in stress due to rubblization occurred in the upper air room pillar where the sagging of the sill pillar relieved most of the vertical load. From the measurements in the sill pillar it appears that it is acting as multiple beams in bending. Stress changes in the retort wall were small probably due to the fact that the upper intermediate level room was developed prior to the pre-rubblization stress measurements.

Phase 3 of the program was to evaluate the suitability of the instrumentation relating stress changes and high temperature measurements over a long period of time (6 months or longer). Data provides some knowledge of proximity limits for stress change-temperature measurement instrumentation. The magnitudes and direction of stresses determined from the limited data collected were in reasonable agreement with the calculated stress changes due to the temperature changes for the conditions measured.

SITE LOCATION

The location of the Logan Wash Experimental test site is shown in Figure 1. The many mine workings are located in the NE 1/4 of Section 25, Township 7 South, Range 97 West, Garfield County, Colorado. The E 1/4 corner of the above section 25 has the ground coordinates of 20,000.0 N - 60,000.0 E. Any drawings in the text with coordinates on them are located with respect to the above control point.



igure 1 - Location of Logan Wash experimental test site.

INTRODUCTION

In order to design or evaluate the stability of an underground structure, a knowledge of the mechanical properties of the material is necessary. Data were obtained from intact oil shale, controlled -surface - retorted oil shale*, and in situ-retorted oil shale materials. The following problems were considered when the plans for laboratory testing were outlined:

A-1. Determine material properties and their relationship to pillar strength and subsidence in the Mahogany zone and in the air room above the retort.

A-2. Determine functional relationship between Fisher Assay and compressive strength, Young's modulus, Poisson's ratio, and apparent specific gravity so that predictive equations can be determined.

A-3. Determine creep characteristics and their effect on subsidence of pillars in both the Mahogany zone and the air room.

B-2. Evaluate controlled-surface-retorted oil shale and its use as backfill to obtain additional support.

C-1. Determine the effect of end loading on the modulus of rupture.

C-2. Determine the relationship of the Brazilian indirect tensile strength test and the modulus of rupture.

EXPERIMENTAL PROCEDURE

NX cores were obtained in the Mahogany zone from drift 400 at the Logan Wash mine and the site is designated as drill site No. 1 in figure 2. A total of 50 feet was sampled by drilling 20 feet into the floor, drilling

*The spent oil shale samples were graded both in size of fragments and yield. Control of these variables was necessary in order to assess the effect of each. These samples were received from the laboratory of Occidental Research Corp. in La Verne, California.

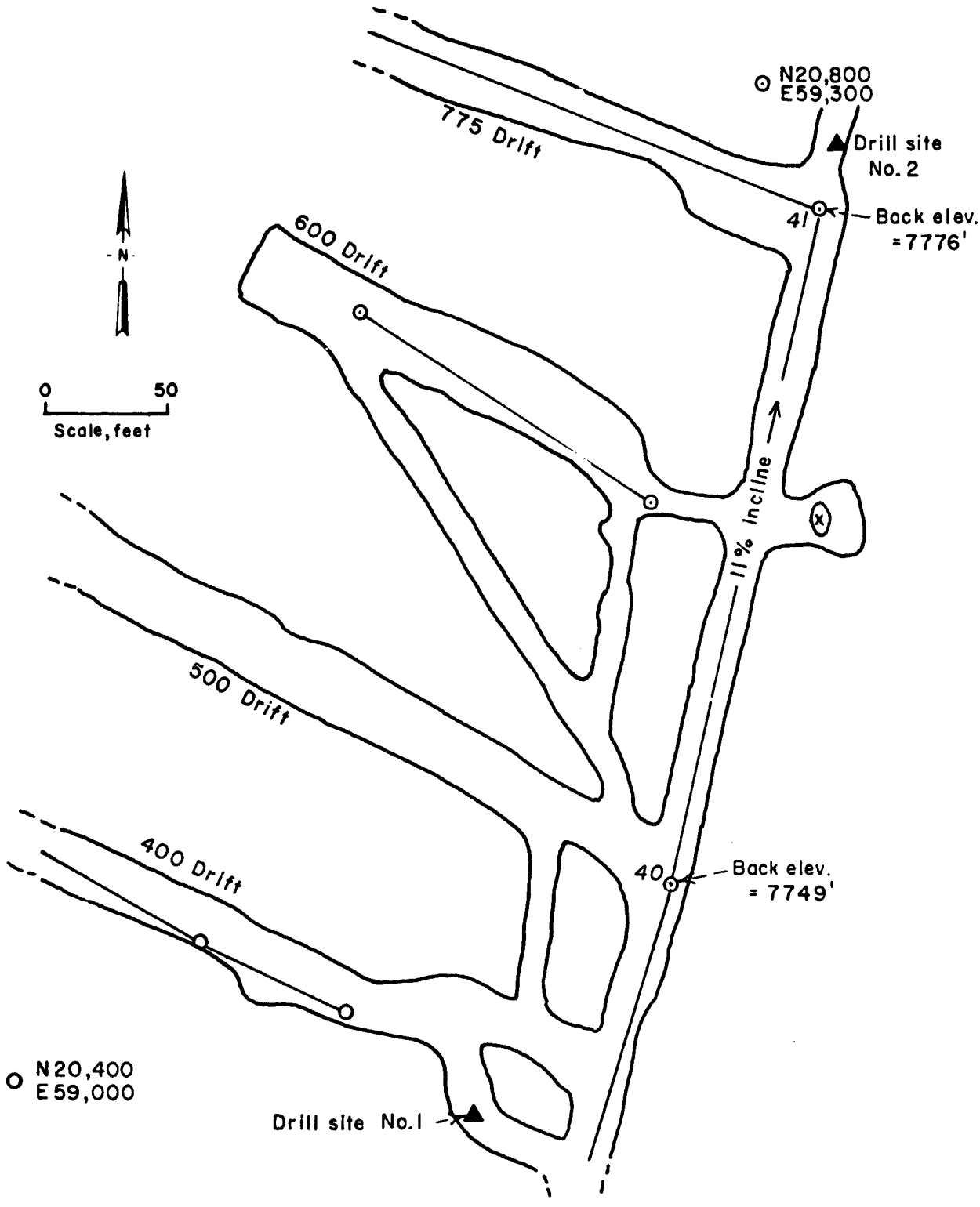


Figure 2 - Drill sites in experimental mine

6-inch cores horizontally in the 10-foot high access drift at various levels, and drilling 20 feet into the roof. The 6-inch horizontal cores were later redrilled vertically with an NX bit (2-1/8" diam.).

Sample Preparation

Samples were cut to the desired lengths and the ends were surface finished with a grinder. End planes were made parallel within a 0·001 in. tolerance. Lengths of cores were kept within a length tolerance of 0.1 in. for the length-to-diameter (L/D) ratio specified. Perpendicular tolerance of the end planes to the axis of the specimen was less than 1 degree.

Equipment Used

A materials test system (MTS)[4] stiff testing machine was used for the testing of the cores. This is a closed loop, servocontrolled hydraulic system with a rated capacity of 600,000 lb. This machine was programed for a constant strain rate of 200 μin/sec.

Linear variable differential transformers (LVDT) were used as the readout device to measure axial as well as lateral deformation under uniaxial tests as shown in figure 3. This physical arrangement allows a determination of Young's modulus (E) and Poisson's ratio (ν).

TESTS CONDUCTED

Uniaxial, triaxial, Brazilian, and modulus of rupture tests were conducted. Young's modulus and Poisson's ratio values were determined at 50% of ultimate stress, as recommended by ASTM standards (2)[5].

[4]Reference to specific brands is made for identification only and does not imply endorsement by the Bureau of Mines.

[5]Underlined numbers in parenthesis refer to the items in the list of references at the end of each section of this report

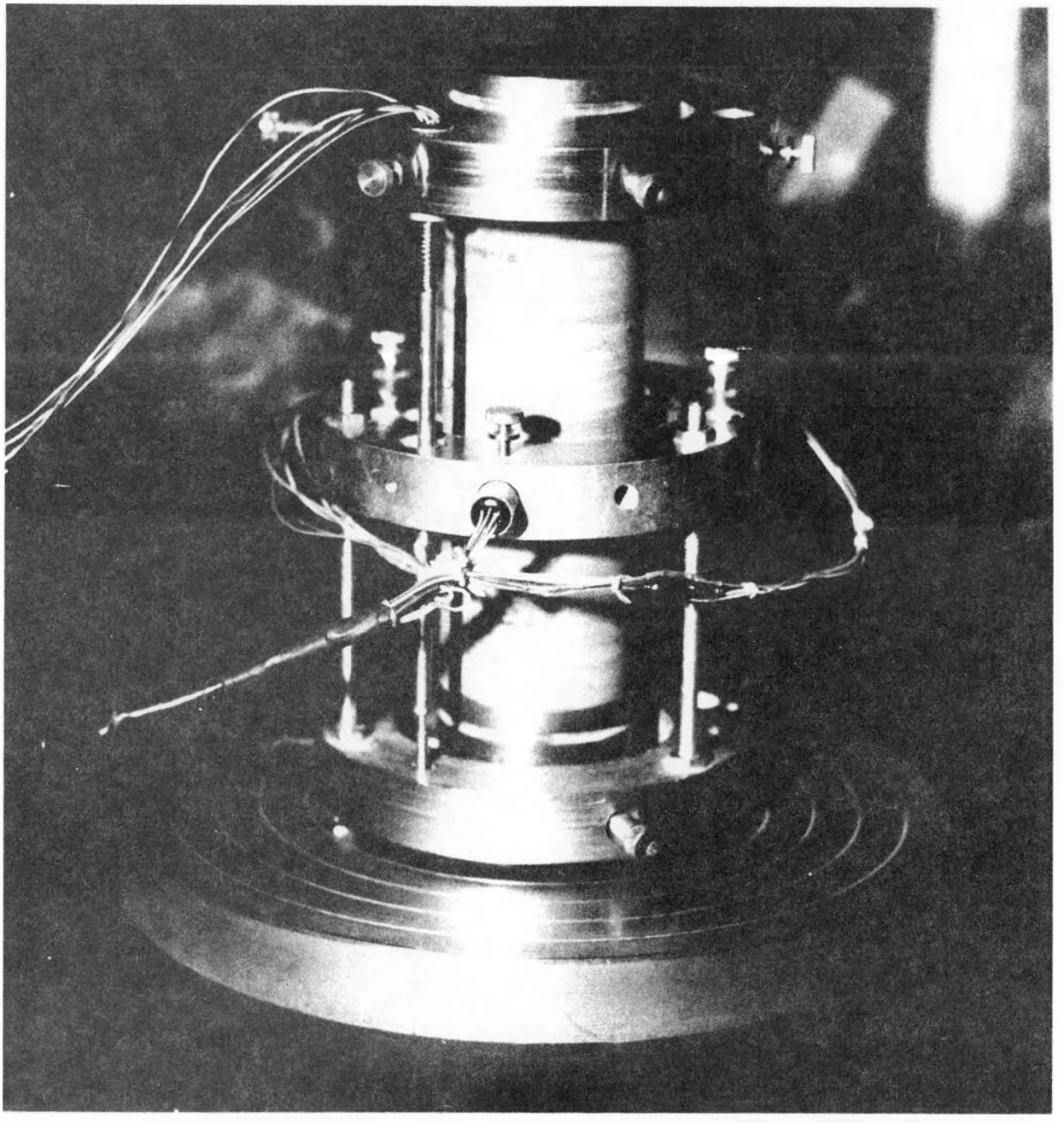


FIGURE 3. -NX Size Oil Shale Core (2-1/8"diam x 5.313"length) Instrumented with Linear Variable Differential Transformer (LVDT) to Measure both Axial and Lateral Displacements.

Uniaxial Tests

Samples with an L/D ratio of 2.5/1 were used. The L/D ratio of 2.5/1 is deemed the best ratio to use so that end constraint from the end platens can be reduced to a minimum or essentially eliminated near the mid point of the test core. Uniaxial tests only were performed on samples from the 20-foot uphole and the 20-foot downhole in drift 400 (floor elev. = 7722.8' and back elev. = 7734.8'). The results are shown in tables 1 and 2.

Triaxial Tests

Triaxial tests were completed on cores that were redrilled from the horizontal 6-inch core. Triaxial testing was conducted using lateral pressures of 500, 1000, 1500, and 2000 psi. Values of the shear strength (S_o) and the coefficient of internal friction (μ_s) were determined by obtaining a Mohr's envelope using the maximum shear stress (τ_s) and mean normal stress (σ_s) technique that has been described elsewhere (3). Results of the testing of these cores from the rib of drift 400 are shown in table 3. Results of the testing of cores from the air room pillar above retort 6 are shown in table 4. The coordinate location of retort 6 is approximately N21150 - E58700.

Brazilian Tests

Cylindrical specimens were loaded across the diameter with the axis of the core horizontal between the platens of the compression machine. A minimum L/D ratio of ½ was used with the ends of the specimen cut perpendicular to the axis; the ends were not finished by grinding. A small 3- by 5-in. cardboard was inserted between the specimen and upper platen which contained

able 1. - Uniaxial tests from the 20-foot (Mahogany Zone) uphole from drift 400 of the experimental mine.

Sample No.	Depth from roof ft.	L x D in.	S. G.	Lat. Press. psi	Comp. Strength psi	Young's mod. x 10^6 at 50% ult. stress secant	Young's mod. x 10^6 at 50% ult. stress tangent	Poisson's ratio sec.	Poisson's ratio tan.	Yield gpt	Remarks
1	0.0 - 0.5	5.295 x 2.220	1.542	0	7595	0.21	0.29	0.29	0.44	82.2	Soft; horizontal fracture
2	0.5 - 1.0	5.293 x "	1.997	0	6565	0.37	0.36	0.32	0.57	45.5	
3	1.0 - 1.5	5.315 x "	1.982	0	7879	0.36	0.35	0.29	0.45	44.7	
5	2.0 - 2.5	5.313 x "	2.035	0	8964	0.68	0.59	0.20	0.27	35.0	
6	3.0 - 3.5	5.303 x "	1.898	0	10256	0.78	0.78	0.34	0.49	45.0	
8	4.5 - 5.0	5.299 x "	2.081	0	9617	0.79	0.73	0.41	0.55	33.4	
9	5.0 - 5.5	5.318 x "	2.223	0	9997	1.20	1.02	0.31	0.43	18.8	
10	5.5 - 6.0	5.314 x "	2.256	0	11186	1.41	1.13	0.27	0.34	18.5	
11	6.0 - 6.5	5.313 x "	2.117	0	9817	0.74	0.67	0.41	0.57	28.1	
12	6.5 - 7.0	5.316 x "	2.218	0	11367	1.28	1.12	0.27	0.41	21.7	
13	7.0 - 7.5	5.316 x "	2.194	0	12142	1.53	1.37	0.27	0.35	23.6	
14	7.5 - 8.0	5.316 x "	2.081	0	11444	0.91	0.80	0.22	0.29	30.1	
15	8.0 - 8.5	5.316 x "	1.862	0	10282	0.72	0.68	0.31	0.42	45.6	High oil content
17	9.5 - 10.0	5.315 x "	2.360	0	20589	2.91	2.79	0.22	0.30	12.6	Hard and stiff
18	10.0 - 10.5	5.315 x "	2.376	0	21648	2.97	2.65	0.21	0.29	11.6	" " "
19	10.5 - 11.0	5.315 x "	2.414	0	27047	3.35	3.36	0.21	0.30	7.3	" " "
20	11.0 - 11.5	5.315 x "	2.326	0	19349	2.35	2.05	0.31	0.42	11.8	" " "
21	11.5 - 12.0	5.315 x "	2.352	0	20020	2.63	2.36	0.19	0.24	11.3	" " "
24	13.0 - 13.5	5.315 x "	2.343	0	15293	2.20	1.93	0.17	0.19	14.9	
25	13.5 - 14.0	5.307 x "	2.262	0	14544	1.77	1.60	0.10	0.12	18.4	
26	14.0 - 14.5	5.305 x "	2.369	0	20150	2.56	2.38	0.39	0.52	11.8	
27	14.5 - 15.0	5.310 x "	2.298	0	16533	2.12	1.76	0.36	0.54	18.1	
28	15.0 - 15.5	5.245 x "	2.201	0	13769	1.43	1.25	0.16	0.22	24.4	
29	15.5 - 16.0	5.313 x "	2.101	0	13433	1.05	0.88	0.36	0.58	29.9	
30	16.0 - 16.5	5.315 x "	2.330	0	17386	2.36	2.05	0.23	0.30	14.8	
31	16.5 - 17.0	5.298 x "	2.364	0	19892	2.66	2.22	0.28	0.38	13.4	
32	17.0 - 17.5	5.311 x "	2.307	0	16275	2.04	1.71	0.15	0.19	17.0	
33	17.5 - 18.0	5.312 x "	2.228	0	14415	1.56	1.29	0.29	0.39	21.9	
35	18.0 - 18.5	5.313 x "	2.182	0	12529	1.19	1.09	0.27	0.40	25.0	
36	19.0 - 19.5	5.316 x "	2.171	0	11496	1.24	1.17	0.29	0.44	26.7	

Table 2. - Uniaxial tests from the 20-foot (Mahogany Zone) downhole from drift 400 of the experimental mine.

Sample No.	Depth from floor ft.	L x D in.	S. G.	Lat. Press. psi	Comp. Strength psi	Young's mod. x 10^6 at 50% ult. stress secant	tangent	Poisson's ratio sec.	tan.	Yield gpt	Remarks
1	0.0 - 0.5	5.315 x 2.220	2.149	0	10592	1.430	1.263	0.17	0.28	20.9	
2	0.5 - 1.0	4.585 x "	2.183	0	9559	1.450	1.343	0.28	0.38	20.1	
3	1.0 - 1.5	5.315 x "	1.972	0	10669	0.733	0.694	0.40	0.52	40.4	
5	2.0 - 3.0	5.314 x 2.140	1.973	0	10564	0.657	0.690	0.38	0.51	40.9	
6	3.0 - 3.5	5.313 x "	1.951	0	6867	0.418	0.360	0.31	0.42	39.4	Sand tar seam in specim
7	3.5 - 4.0	5.311 x "	2.019	0	7145	0.505	0.456	0.29	0.46	36.1	" " " " "
8	4.0 - 4.5	5.314 x "	1.858	0	10008	0.611	0.592	0.31	0.39	44.8	
9	4.5 - 5.0	5.313 x "	2.067	0	8896	0.704	0.643	0.30	0.45	31.2	
10	5.0 - 5.5	5.300 x "	2.230	0	11510	1.433	1.248	0.35	0.51	20.0	
11	5.5 - 6.0	4.967 x "	2.206	0	11343	1.508	1.299	0.30	0.48	16.3	
12	6.0 - 6.5	5.314 x "	2.176	0	10453	1.106	0.988	0.26	0.35	26.3	
13	6.5 - 7.0	5.285 x "	1.952	0	3340	0.520	0.477	0.35	0.51	38.3	
14	7.5 - 8.0	5.305 x "	2.224	0	12594	1.634	1.515	0.25	0.33	14.7	
15	8.0 - 8.5	5.313 x "	2.165	0	11732	1.134	0.907	0.28	0.39	21.8	
16	8.5 - 9.0	5.310 x "	2.259	0	13067	1.714	1.493	0.19	0.20	13.2	
17	9.0 - 9.5	5.312 x "	2.161	0	11732	1.350	1.177	0.28	0.41	16.3	
18	9.5 - 10.0	5.314 x "	2.218	0	12094	1.470	1.314	0.19	0.27	14.6	
19	10.0 - 10.5	5.298 x "	1.658	0	9536	0.492	0.486	0.38	0.59	45.7	High oil content
20	10.7 - 11.2	5.313 x "	2.208	0	12769	1.678	1.437	0.35	0.48	19.8	
21	11.2 - 11.7	5.313 x "	2.265	0	14762	1.943	1.736	0.26	0.35	36.2	
22	11.7 - 12.2	5.306 x "	2.255	0	13706	1.996	1.892	0.41	0.60	----	
23	12.2 - 12.7	5.308 x "	2.242	0	13650	1.810	1.631	0.33	0.45	12.8	
25	13.0 - 13.5	5.268 x "	1.988	0	9925	0.756	0.739	0.30	0.43	26.8	
26	13.5 - 14.2	5.300 x "	2.033	0	10203	0.969	0.898	0.30	0.42	24.8	
27	14.2 - 14.7	5.312 x "	2.131	0	10036	1.153	1.133	0.38	0.57	29.0	
28	14.7 - 15.2	5.313 x "	2.039	0	8201	0.534	0.532	0.41	0.51	28.2	
29	15.2 - 16.0	5.309 x "	2.142	0	9953	0.889	0.833	0.30	0.50	28.2	
31	16.5 - 17.0	5.310 x "	2.170	0	11982	1.290	1.102	0.24	0.32	24.0	
32	17.0 - 17.6	5.311 x "	2.064	0	9147	0.833	0.811	0.23	0.38	32.9	
33	17.6 - 18.1	5.311 x "	1.980	0	9786	0.614	0.568	0.34	0.54	38.4	
34	18.1 - 18.6	4.993 x "	1.969	0	9647	0.656	0.574	0.44	0.60	41.8	
35	18.6 - 19.0	5.315 x "	2.208	0	12733	1.407	1.207	0.33	0.48	26.5	
36	19.0 - 19.5	5.313 x "	2.188	0	11676	1.288	2.082	0.31	0.47	23.4	
37	19.5 - 20.0	5.316 x "	2.151	0	11954	1.071	0.891	0.42	0.64	26.5	
38	20.0 - 20.6	5.305 x "	2.204	0	13706	1.636	1.307	0.34	0.46	20.6	

able 3. - Triaxial, Brazilian, and Modulus of Rupture tests of cores from the rib from drift 400 of the experimental mine.

IDDLE HOLE IN RIB

ample No.	L x D in.	S. G.	Lat. Press. psi	Comp. Strength psi	Young's mod. x 10^6 at 50% ult. stress secant	tangent	Poisson's ratio sec.	tan.	Yield gpt	Shear Strength psi	Coef. of Int. Frie.	Remarks
20	5.311 x 2.105	2.232	0	12643	1.83	1.57	0.37	0.52	17.1			
21	5.312 x "	2.244	0	12701	1.80	1.55	0.34	0.48	16.3			
22	5.314 x "	2.245	500	13735	2.09	1.65	----	----	15.8	4547	0.34216	
23	5.315 x "	2.255	1000	14798	2.09	1.69	----	----	15.2			
24	5.316 x "	2.253	1500	15747	2.12	1.58	----	----	15.8			
25	5.313 x "	2.251	2000	16494	2.08	1.62	----	----	16.0			
OTTOM HOLE IN RIB												
26	5.310 x 2.105	1.858	0	9856	0.614	0.628	0.42	0.53	47.9			
27	5.315 x "	1.646	0	10028	0.606	0.582	0.44	0.55	51.0			
28	5.310 x "	1.879	500	10057	0.718	0.610	----	----	48.4			
29	5.313 x "	1.872	1000	8678	0.732	0.621	----	----	48.2	4358	0.11603	
29A	5.314 x "	1.879	1000	11350	0.745	0.622	----	----	----			Fractured; Not used in Mohr's env. analysis
30	5.316 x "	1.872	1500	11781	0.724	0.541	----	----	49.2			
31	5.313 x "	1.868	2000	12212	0.747	0.537	----	----	49.0			
OP HOLE IN RIB												
1	5.315 x 2.105	1.868	0	9856	0.620	0.652	0.41	0.54	47.3			
2	5.302 x "	1.862	0	10086	0.619	0.625	0.41	0.57	48.9			
3	5.305 x "	1.853	500	10345	0.700	0.547	----	----	48.3	N. V.	N. V.	
4	5.313 x "	1.870	1000	11264	0.766	0.577	----	----	46.7			
5	5.311 x "	1.868	1500	11437	0.743	0.545	----	----	47.0			
6	5.323 x "	1.868	2000	11810	0.758	0.567	----	----	47.8			

RAZILIAN TESTS

Sample No.	Indirect Tensile strength psi	Mean psi	Standard Deviation psi	Yield gpt
7	823			46.0
8	680			46.5
9	773	796	100	47.2
10	756			48.3
11	949			47.0

MODULUS OF RUPTURE (FLEXURAL STRENGTH)

Sample No.	Flexural Strength psi	Mean psi	Standard Deviation psi	Yield gpt
13	2286			47.0
14	1502	1706	509	49.7
15	1331			47.8

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Table 4. - Triaxial, Brazilian, and Modulus of Rupture tests of cores from the pillar in air room above retort #6.

PILLAR IN AIR ROOM ABOVE RETORT # 6

Sample No.	L x D in.	S. G.	Lat. Press. psi	Comp. Strength psi	Young's mod. x 10^6 at 50% of ult. load secant	Young's mod. x 10^6 at 50% of ult. load tangent	Poisson's ratio sec.	Poisson's ratio tan.	Shear Strength psi	Coef. of Int. Fric.	Remarks
3A	4.852 x 2.080	2.331	0	10889	1.73	1.56	0.26	0.36			Cores obtained about 6 ft. above ground level. Cores redrilled vertically from 6-inch diam. core.
3B	5.112 x "	2.324	0	11595	1.60	1.41	0.27	0.36			
3C	4.815 x "	2.318	500	13979	1.51	1.32	----	----			
3D	4.983 x "	2.320	500	14126	1.55	1.50	----	----			
3E	4.999 x "	2.312	1000	15244	1.62	1.46	----	----			
3F	4.909 x "	2.313	1000	15538	1.61	1.48	----	----	2705	0.80984	
4A	4.918 x "	2.325	0	10889	1.58	1.42	0.35	0.50			
4B	4.492 x "	2.318	500	14185	1.63	1.52	----	----			
4C	4.770 x "	2.322	1000	15833	1.67	1.52	----	----			
4D	4.944 x "	2.328	1500	17363	1.76	1.51	----	----			
4E	4.456 x "	2.338	1500	18099	1.72	1.61	----	----			

BRAZILIAN TESTS

Sample No.	L x D in.	S. G.	Indirect Tensile Strength psi	Average Strength psi	Std. Dev. psi	Remarks
1F	1.575 x 1.737	2.262	1266			#1 core, 6-inch in diam., taken from hole directly above other 6-inch hole.
1G	1.575 x "	2.267	777			
1H	1.583 x "	2.277	1172			
6A	1.840 x 2.080	2.319	828	932	219	Samples #6A and 6C taken from top portion of core redrilled v
6B	1.835 x "	2.320	702			
6C	1.840 x "	2.315	1003			Samples #6B and 6D taken from bottom portion of core redrille
6D	1.840 x "	2.308	777			

MODULUS OF RUPTURE TESTS

Sample No.	L x D in.	S. G.	Outer Fiber Tensile Strength psi	Average Strength psi	Std. Dev. psi	Remarks
1A	6.125 x 2.080	2.305	424			Distance between knife edges = 5 inches.
1B	6.012 x "	2.344	396	410	20	
5A	6.102 x 2.080	2.316	614			
2D	5.375 x 1.515	2.312	641			
2E	5.138 x "	2.309	624	763	149	
5E	5.540 x "	2.324	952			
5F	5.375 x "	2.323	886			

a spherical seat, and another was placed between the bottom platen and the specimen (4).

This tensile strength, calculated by the following equation gives a value which is usually greater than the direct tensile strength and less than the flexural strength:

$$T_o = \frac{2F_c}{\pi DL}$$

where F_c = failure load, and D and L are the diameter and length of the specimen.

Brazilian tests of cores from the rib are shown in table 3. The tests of cores from the pillar in the air room are shown in table 4.

Modulus of Rupture Tests

This test is a measure of the outer fiber tensile strength of a material. It is determined by loading a cylindrical specimen to failure in a three-point loading setup. The flexural strength, R_o, for a cylindrical specimen of diameter, D, is:

$$R_o = \frac{8\ F_c L}{\pi\ D^3}$$

where F_c = applied load at failure,

L = length between knife edges of lower plate.

Modulus of rupture test results are shown in tables 3 and 4.

ANALYSIS OF DATA

Regression Analyses

Regression analyses were completed on data from the Mahogany zone relating Fischer assay values or yield in gpt to compressive strength, apparent specific gravity, Young's modulus and Poisson's ratio. Fischer

assays were made on individual samples tested and not on samples taken over a 1-foot interval. Table 5 gives a summary of the equations and the correlation coefficients. Correlation coefficients of 0.90 or greater are considered excellent for rock mechanics studies. Regression analysis of Poisson's ratio versus yield gave a correlation coefficient of 0.576 which is poor. The computer plots of these regression analyses are shown in figures 4, 5, 6, and 7.

Analysis of Creep Characteristics

Time-deformation (creep) studies were made on cores taken from the Mahogany zone in drift 400 of the experimental mine and from the pillar in the air room above retort No. 6.

A total of 18 creep tests were completed using a constant load technique. Each test required a time period from 90 to 210 days. The creep test period was based on a decision as to whether the sample had reached the secondary creep stage. If it was the decision that it had, then the test was terminated. Obviously the greater the yield of the sample, the longer time period it took to reach the secondary creep stage. L/D ratio was approximately 1/1. Table 6 shows the samples tested. Table 6 would indicate that if the apparent specific gravity is very nearly equal, the higher the stress, the greater will be the final steady state creep rate.

Because it was recongnized that the strain rate is stress-dependent, the same sample should be tested at various stress levels. The same sample should be used to obtain meaningful results because of the ever-changing nature of the bedded material in a vertical direction. Samples were loaded to a selected load level to simulate the in situ field condition. Deformation of samples was monitored mechanically by three precision dial gages, and an average of the three readings was then used. The testing equipment

Table 5 - Regression Equations for Mahogany Zone Data

Parameter	Regression Equation	Sample Size	Correlation Coefficient
Compressive Strength	$Y = 6650 + \frac{165948}{x}$	63	0.86
Apparent Specific Gravity	$Y = \frac{1}{0.3924+.0029x}$	64	0.97
Young's modulus	$Y = -.0007 + \frac{28.80}{x}$	64	0.94
Poisson's ratio	$Y = 0.1954+.0039x$	62	0.58

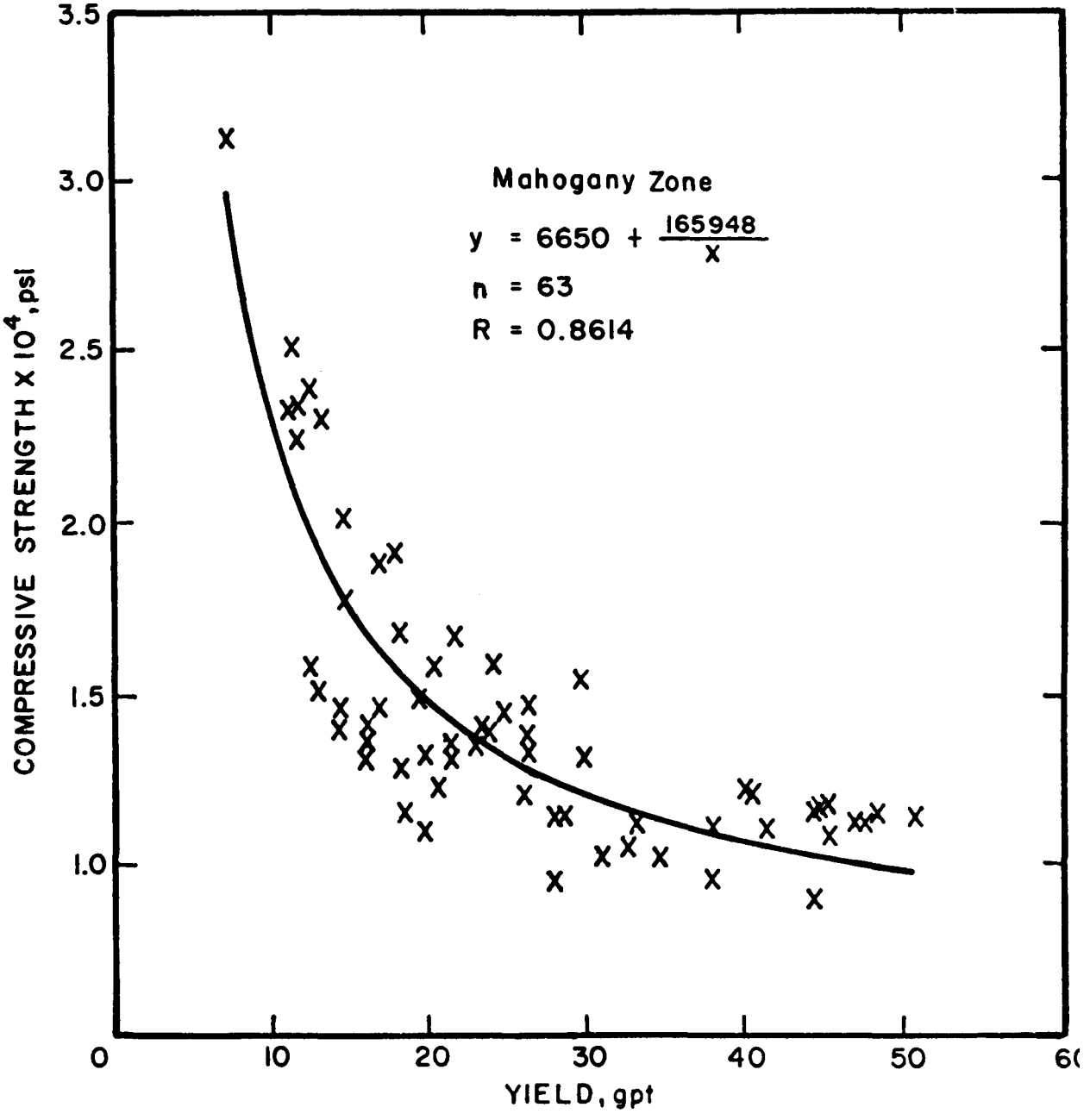


Figure 4 - Compressive strength versus yield.

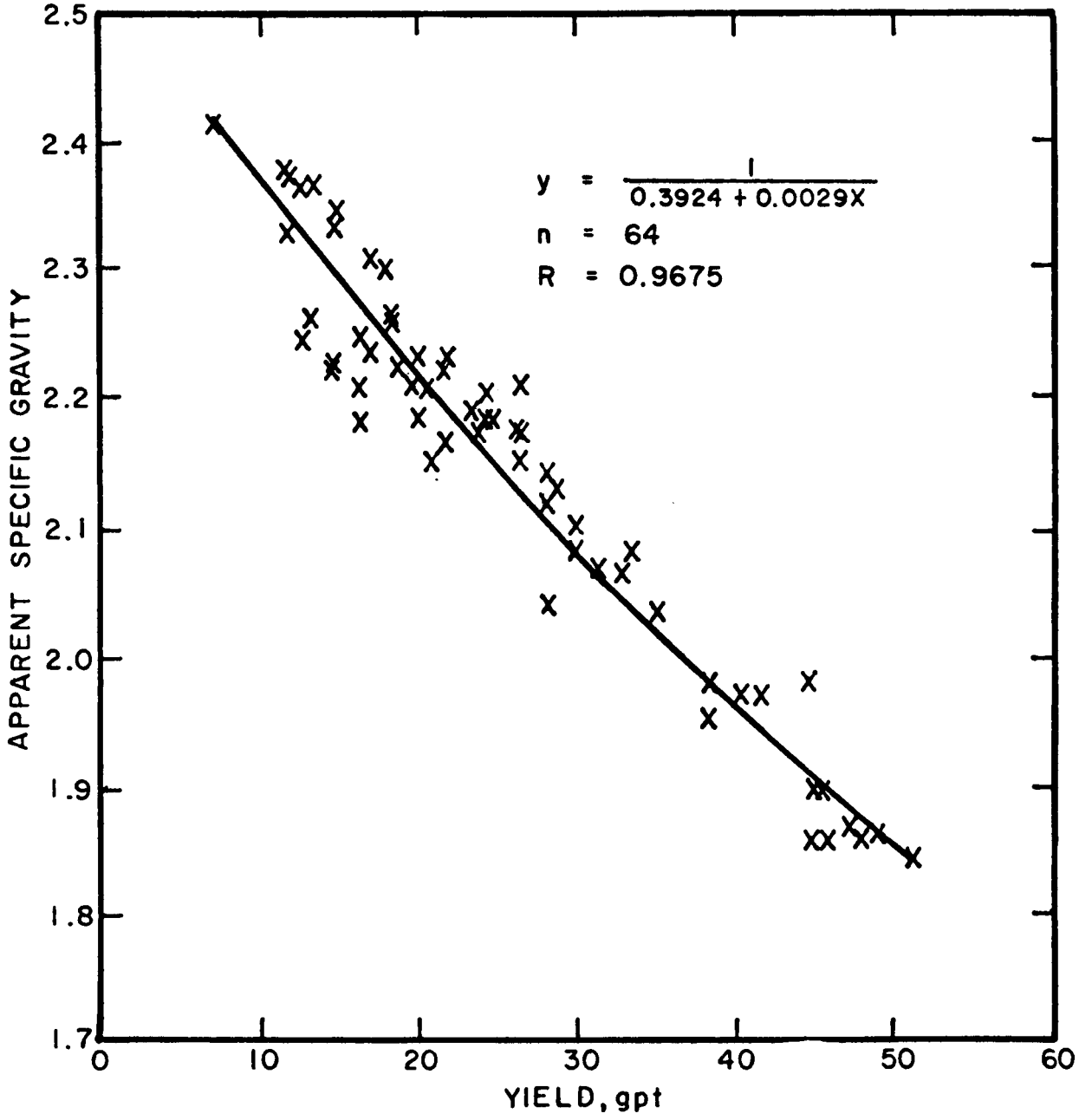


Figure 5 - Apparent specific gravity versus yield.

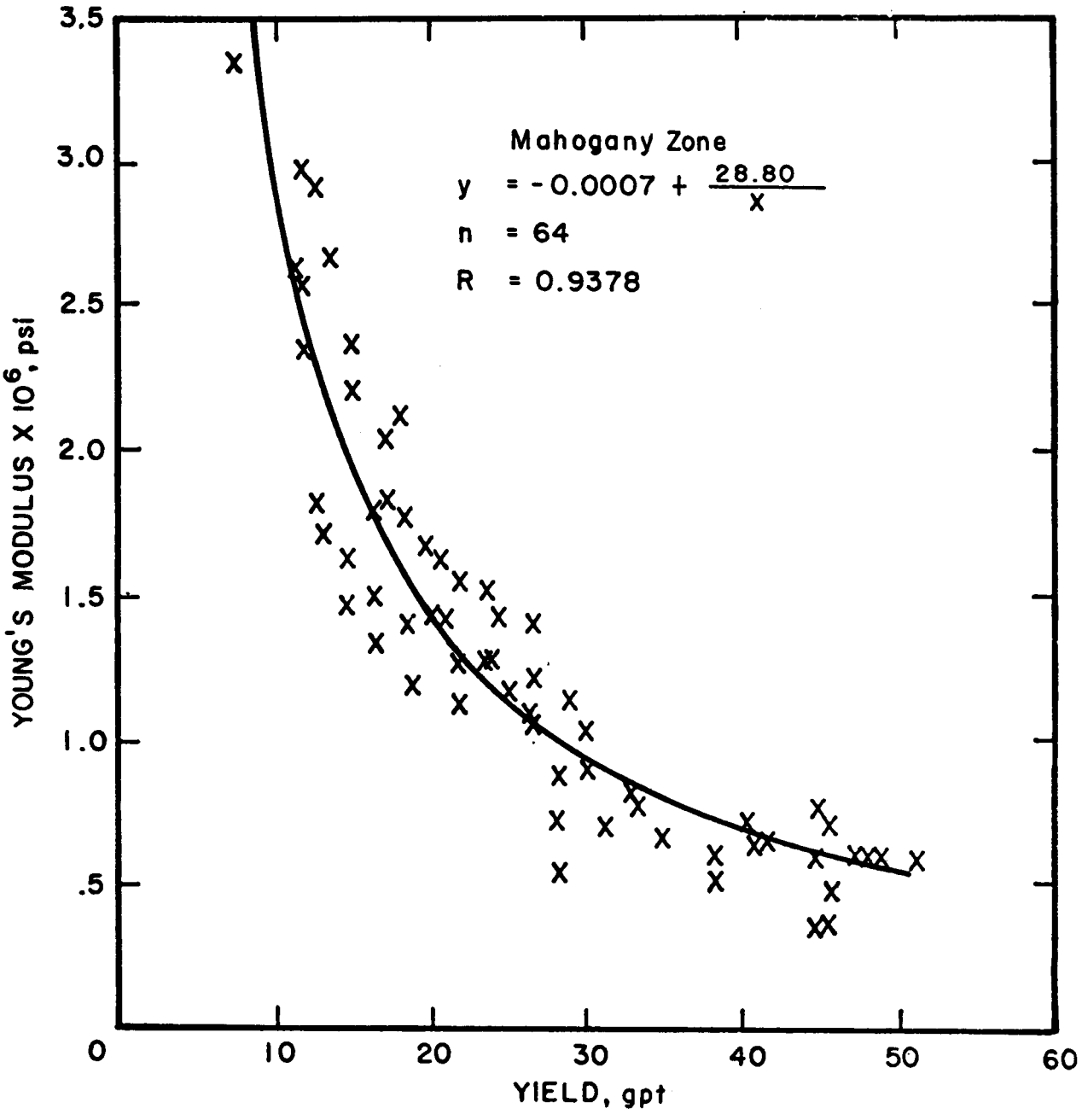


Figure 6 - Young's modulus versus yield.

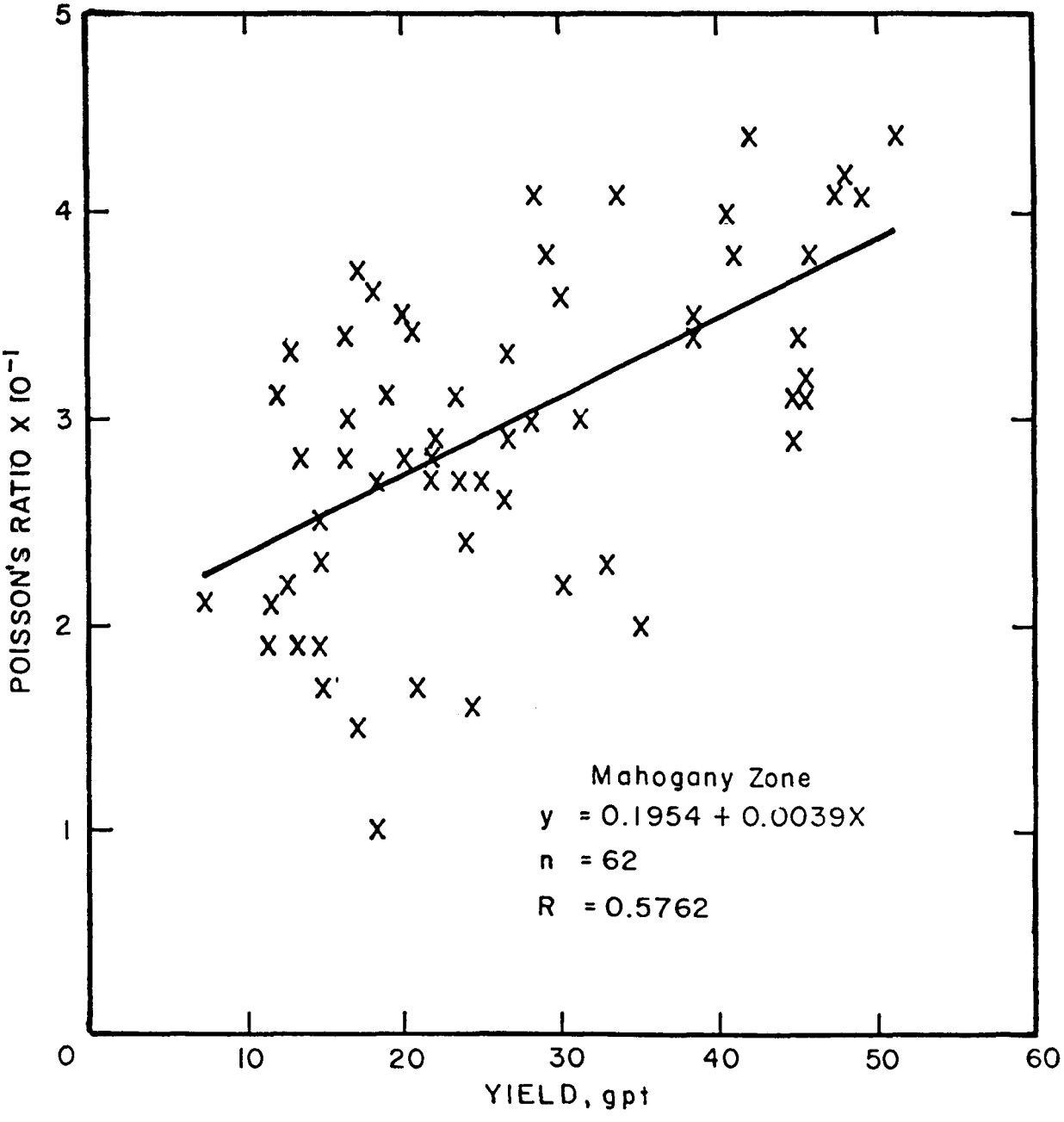


Figure 7 - Poisson's ratio versus yield.

Table 6. - Creep rates for samples tested.

Sample No.	Location	Length of test days	S. G.	L/D	Stress Applied psi	Yield gpt	Final Steady State Creep Rate μ in/in/day
1C	Pillar in air rm. above retort #6	90	2.272	1.075/1	3882	17.2	10.24
1D	" " "	"	2.273	1.061/1	5546	18.2	11.54
1E	" " "	"	2.272	1.024/1	7210	16.9	13.03
2A	" " "	"	2.340	1.007/1	7357	14.6	10.20
2B	" " "	"	2.327	1.022/1	5592	14.5	10.10
2C	" " "	"	2.329	1.020/1	3973	14.5	8.50
Downhole #4	Mahogany Zone in drift 400	"	2.122	0.967/1	3875	31.6	8.02
"	" " "	"	"	"	5425	"	10.04
"	" " "	"	"	"	6975	"	21.43
Downhole #24	" "	"	2.281	1.005/1	4448	29.6	3.98
"	" "	"	"	"	6116	"	4.09
"	" "	"	"	"	8062	"	4.29
Top Rib #12	" "	"	1.887	0.991/1	4310	45.5	8.09
"	" "	"	"	"	6034	"	6.81
"	" "	"	"	"	7902	"	25.08
Uphole #4	" "	210	1.587	0.982/1	2842	78.7	18.90
"	" "	150	"	"	4133	"	127.70
"	" "	"	"	"	5425	"	51.40

was kept in an air-conditioned room in which the temperature was kept constant at 74°F. Humidity controls were not available. The gages were read daily and the load was adjusted to the initial load level to offset the creep and the resulting load decrease of approximately 100 to 200 lb. daily.

Samples Downhole #4, Downhole #24, and Top Rib #12 were tested at three different stress levels and were analyzed to see if the data would fit the Burger's equation (5)given below:

$$\varepsilon = \frac{\sigma_o}{E} + B\sigma_o{}^{\alpha}t + C\sigma_o\,(1 - e^{-\beta t}),$$

where

ε = strain,

σ_o = constant stress,

t = time of stress application,

$\frac{\sigma_o}{E}$ = instantaneous elastic strain

$B\sigma_o{}^{\alpha}t$ = steady-state creep,

$C\sigma_o(1-e^{-\beta t})$ = initial or transient creep.

Figure 8 shows the components of the Burger Equation.

A log-log plot of the stress against the steady state creep rate gave the value of the constant "B" and the slope α for a given specific gravity or sample and is shown in figure 9.

A semi-logarithmic plot of the transient creep against the time in days will give the slope of the line or the β value for a given stress value and is shown in figure 10.

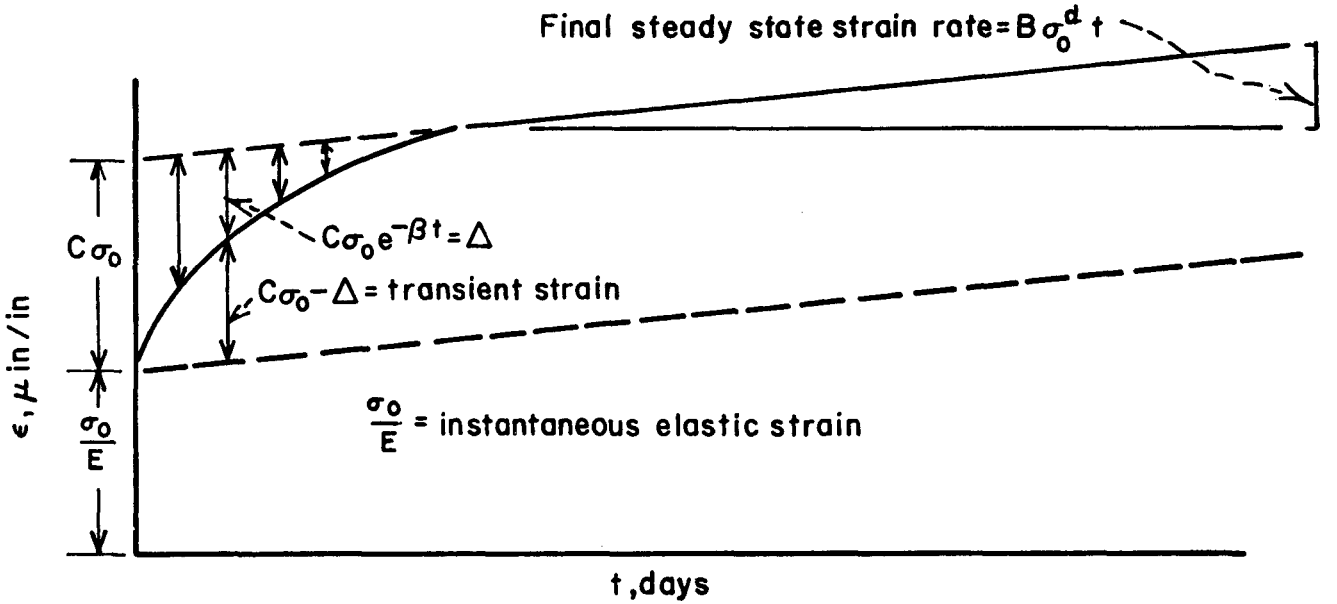


Figure 8 - Components of Burger equation.

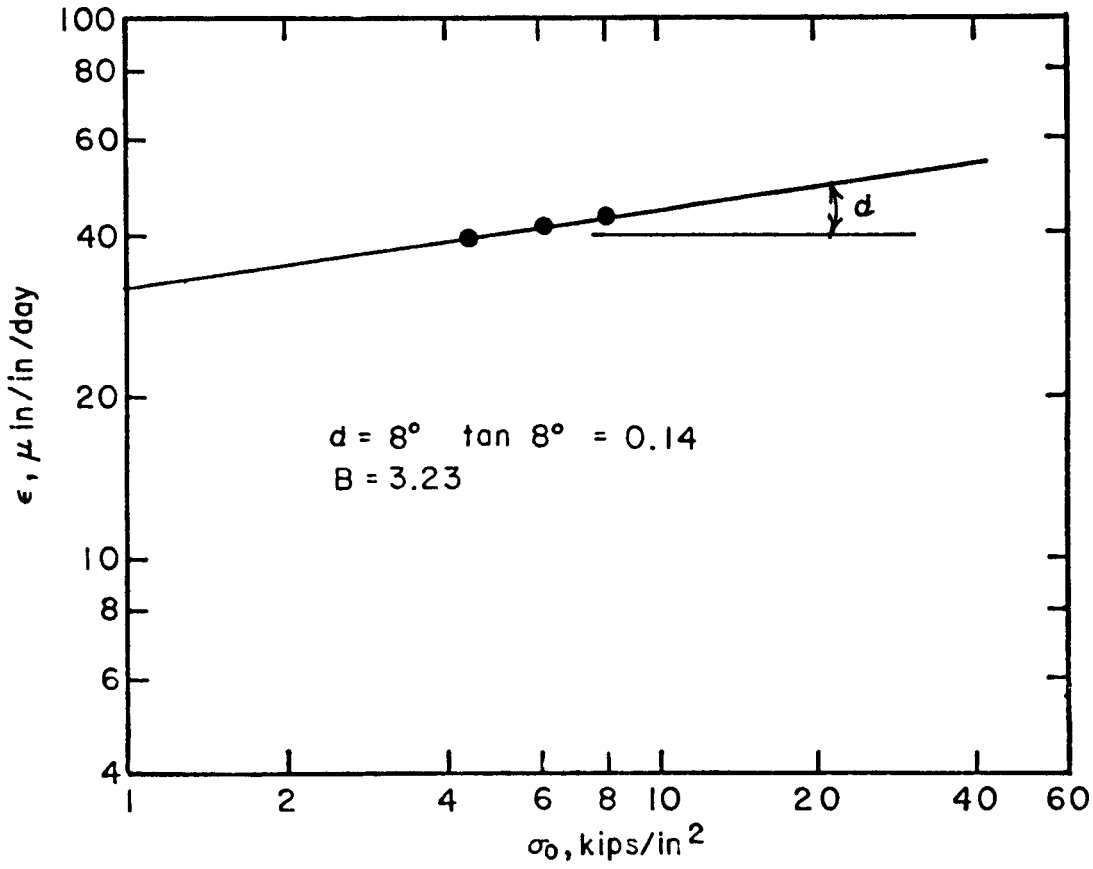


Figure 9 - Strain rate versus axial stress.

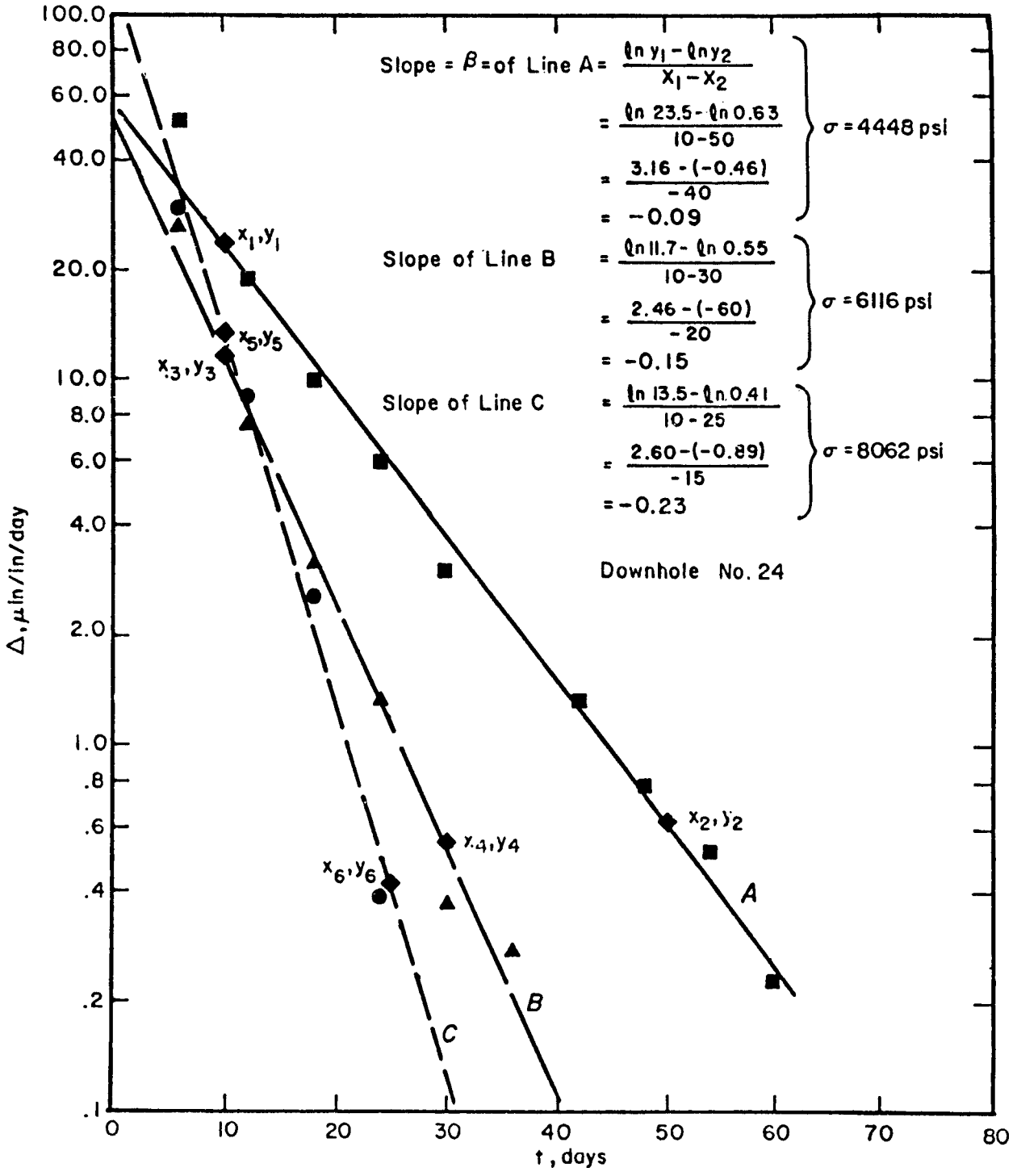


Figure 10 - Strain rate versus time.

Thus, the following equations were generated where the stress levels are expressed in kips (1000# of force) per sq. in.:

For specific gravity ≤ 1.9 and for $\sigma_o \leq 4.310$ kips/in^2:

$$\epsilon = \frac{\sigma_o}{0.891 \times 10^3} + 0.6\,\sigma_o^{1.80405}\,(t) + 1586\,(1 - e^{-0.127t})$$

For $4.310 < \sigma_o < 6.0$ kips/in^2:

$$\epsilon = \frac{\sigma_o}{0.686 \times 10^3} + 0.6\sigma_o^{1.80405}\,(t) + 1576\,(1 - e^{-0.135t})$$

For $\sigma_o > 6.0$ kips/in^2:

$$\epsilon = \frac{\sigma_o}{0.639 \times 10^3} + 0.6\,\sigma_o^{1.80405}\,(t) + 2889\,(1 - e^{-0.147t})$$

For $1.9 <$ S. G. < 2.2 and for $\sigma_o \leq 4.0$ kips/in^2:

$$\epsilon = \frac{\sigma_o}{0.711 \times 10^3} + 1.13\,\sigma_o^{1.4281}\,(t) + 1074\,(1 - e^{-0.12t})$$

For $4.0 < \sigma_o < 5.5$ kips/in^2:

$$\epsilon = \frac{\sigma_o}{0.660 \times 10^3} + 1.13\,\sigma_o^{1.4281}\,(t) + 1067\,(1 - e^{-0.15t})$$

For $\sigma_o > 5.5$ kips/in^2:

$$\epsilon = \frac{\sigma_o}{0.627 \times 10^3} + 1.13\,\sigma_o^{1.4281}\,(t) + 1602\,(1 - e^{-0.17t})$$

For S. G. > 2.2 and for $\sigma_o \leq 4.0$ kips/in^2:

$$\epsilon = \frac{\sigma_o}{1.30 \times 10^3} + 3.23\,\sigma_o^{0.14054}\,(t) + 549\,(1 - e^{-0.09t})$$

For $4.0 < \sigma_o < 6.0$ kips/in^2:

$$\epsilon = \frac{\sigma_o}{1.30 \times 10^3} + 3.23\,\sigma_o^{0.14054}\,(t) + 358\,(1 - e^{-0.15t})$$

For $\sigma_o > 6.0$ kips/in^2:

$$\epsilon = \frac{\sigma_o}{1.30 \times 10^3} + 3.23\,\sigma_o^{0.14054}\,(t) + 591\,(1 - e^{-0.23t})\ .$$

Since time displacement of a pillar is a function of the yield or specific gravity and the stress level to which it is subject, comparisons are made with the values of "E" and "$C\sigma_o$" as determined by the equations. The comparisons are made for a presumed time span of 10 years for a 20-foot pillar. Results are given in table 7. The equations would appear to be reasonable, with the greatest error of 8.3% shown in sample No. 2A. All of the percentages of error are on the low side. It should be noted that on a long-term creep test such as the example given, the final steady state strain rate accounts for almost 75% of the total strain. Thus, the instantaneous elastic strain and the transient strain contributes about 25% of the total strain. For a short-term test of 90 days, the instantaneous elastic strain is the major contributor to the total strain.

No analysis could be made of a sample Uphole #4 because the creep rate for the highest stress value was much lower than for the intermediate stress value. This would indicate that strain hardening had probably taken place. This very-rich oil yield sample indicates a strain rate of 127.7 μin/in/day at a stress level of 4133 psi.

One could probably safely conclude from the limited study made here that closure should not be a problem.

IN SITU RETORTED SHALE

The purpose of testing the in situ retorted oil shale is to obtain an evaluation of the subsidence potential.

able 7. - Comparison of displacements for a 20-foot pillar under stress for 10 years.

ample No.	S. G.	σ_c kips/in^2	E x 10^3 kips/in^2	C σ_c μin/in	t days	ε μin/in	Displacement for 20-ft pillar, inches	Percent error	Yield gpt	Remarks
1C	2.272	3.882	1.290	934	3650	18208	4.370	2.2	17.2	#Calculated displacement usin E and C σ_c from curves of sam
			1.300	549	"	17800	4.272		"	##Calculated displacement usin equations.
1D	2.273	5.446	1.607	1542	"	19992	4.798	0.6	18.2	#
			1.230	358	"	19866	4.768		"	##
1E	2.272	7.211	1.640	2030	"	21989	5.277	0.5	16.9	#
			1.260	591	"	21876	5.250		"	##
2A	2.340	7.357	1.205	2326	"	24037	5.768	8.3	14.6	#
			1.260	591	"	22036	5.289		"	##
2B	2.327	5.591	1.203	1491	"	21155	5.077	5.8	14.5	#
			1.230	358	"	19920	4.781		"	##
2C	2.329	3.973	1.067	1056	"	19092	4.582	6.2	14.5	#
			1.300	549	"	17917	4.300		"	##

Various attempts were made to obtain drill cores of the retorted oil shale from retort #1. All attempts failed. Therefore small blocks were obtained from the retort. These were later cut into small cubes of various sizes and tested. The results of the testing are shown in table 8. Average percent compaction is equal to 2.5%.

CONTROLLED-SURFACE-RETORTED SHALE

The purpose of testing the controlled-surface-retorted shale was to make an evaluation of the material for use as backfill material to obtain additional strength around supporting pillars.

The results of the tests are shown in figure 11. The results show that for the same particle size and for a given load, the compaction is greater for the shale with the greatest yield (Sample 4A has greater compaction than sample 1B and sample 1B has greater compaction than sample 5A). The figure would also indicate that for the same yield, the larger the particle size, the greater will be the compaction for a given load. (Sample 3A has greater compaction than sample 4A). Maximum percent compaction at the highest stress level is noted in figure 11.

ROOF HORIZON RESULTS

A significant effort was made to determine the effect of end loading on the modulus of rupture. This is a very important concept in design for it allows the engineer to take advantage of any horizontal stresses that might be present so that a room can be oriented in the most efficient direction so that roof spans can be enlarged, thereby increasing the extraction ratio.

Table 8. - Properties of in situ retorted oil shale.

Preliminary test results on spent oil shale samples
Samples produced from small blocks taken from Retort #1

Sample No.	Height in.	Width in.	Depth in.	Apparent Specific Gravity	Comp. Strength psi	Static Young's mod. x 10^6, psi sec.	Static Young's mod. x 10^6, psi tan.	Dynamic Young's mod. x 10^6, psi	Remarks
1A#	1.060	1.385	1.330	1.394	1208	----	----	----	Loaded perpend. to bedding
1	2.870	2.682	2.650	1.587	935	0.067	0.049	0.037	" " " "
2	2.900	2.178	2.008	1.770	960	0.070	0.052	0.091	" " " "
3	1.636	1.476	1.575	1.557	861	----	----	0.081	" " " "
5	1.530	1.310	1.420	1.487	995	----	----	0.128	" " " "
					X = 992	0.069	0.051	0.084	X = Average value
#Tested sample thrown away					s = 130	0.002	0.002	0.037	s = Standard deviation
4	1.610	1.805	1.350	1.563	1262	----	----	0.065	Loaded parallel to bedding

Percent Compaction:

Sample #2: 2.4%

Sample #1: 2.6%

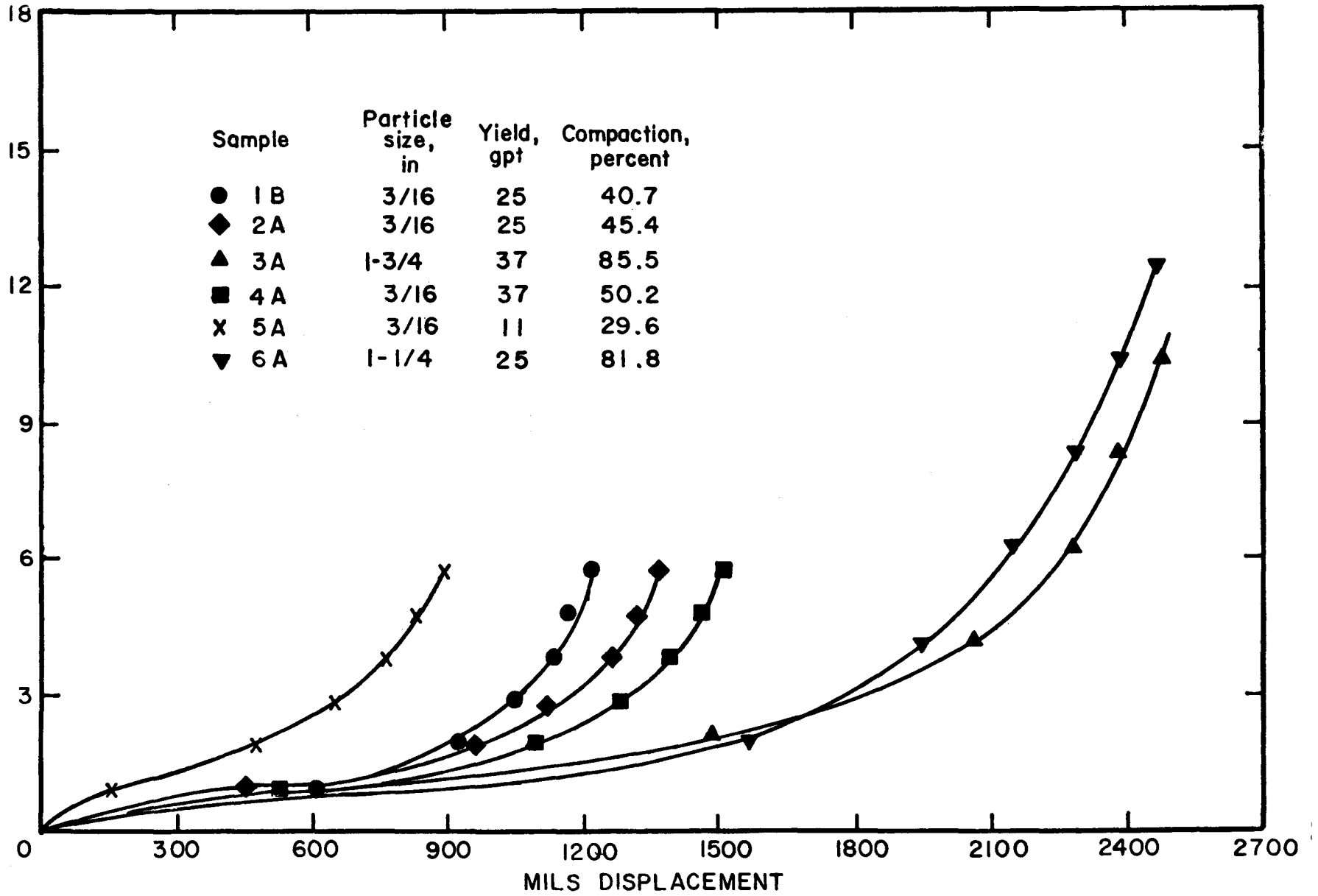


Figure 11 - Compaction tests showing mils displacement versus load.

NX cores from the roof rock in drift 775, designated as drill site 2 in figure 2, were obtained by drilling horizontally into the drift wall and were tested by the modulus of rupture technique. End loads of 500, 1000, 1500, and 2000 psi were applied to determine the effect of end loading on the modulus of rupture.

The results of the test are shown in figure 12. There is an approximate 1250 psi increase in the modulus of rupture value with each end pressure increase of 500 psi.

Indirect tensile strength tests were also made on vertical cores from the same area. Vertical core redrilled from 6" diameter horizontal core provided a suite of core to run a conventional Mohr's envelope. Thus, we were able to determine relationships of various paremeters to each other for cores from the same horizon with the yield of 37.75 gpt. These are tabulated in table 9.

Table 9. - Relationships of various parameters to each other from cores obtained from roof rock in drift 775.

Uniaxial Comp. Strength psi (C_o)	Shear Strength psi	Tan Φ (Coef. of Int. Fric.)	Indirect Tensile Strength psi	Modulus of Rupture Psi
10931 ± 582	4544	0.19337	1193 ± 184	2156 ± 207

The purpose of these tests was to establish the relationship of the modulus of rupture to the easily-performed indirect tensile strength test

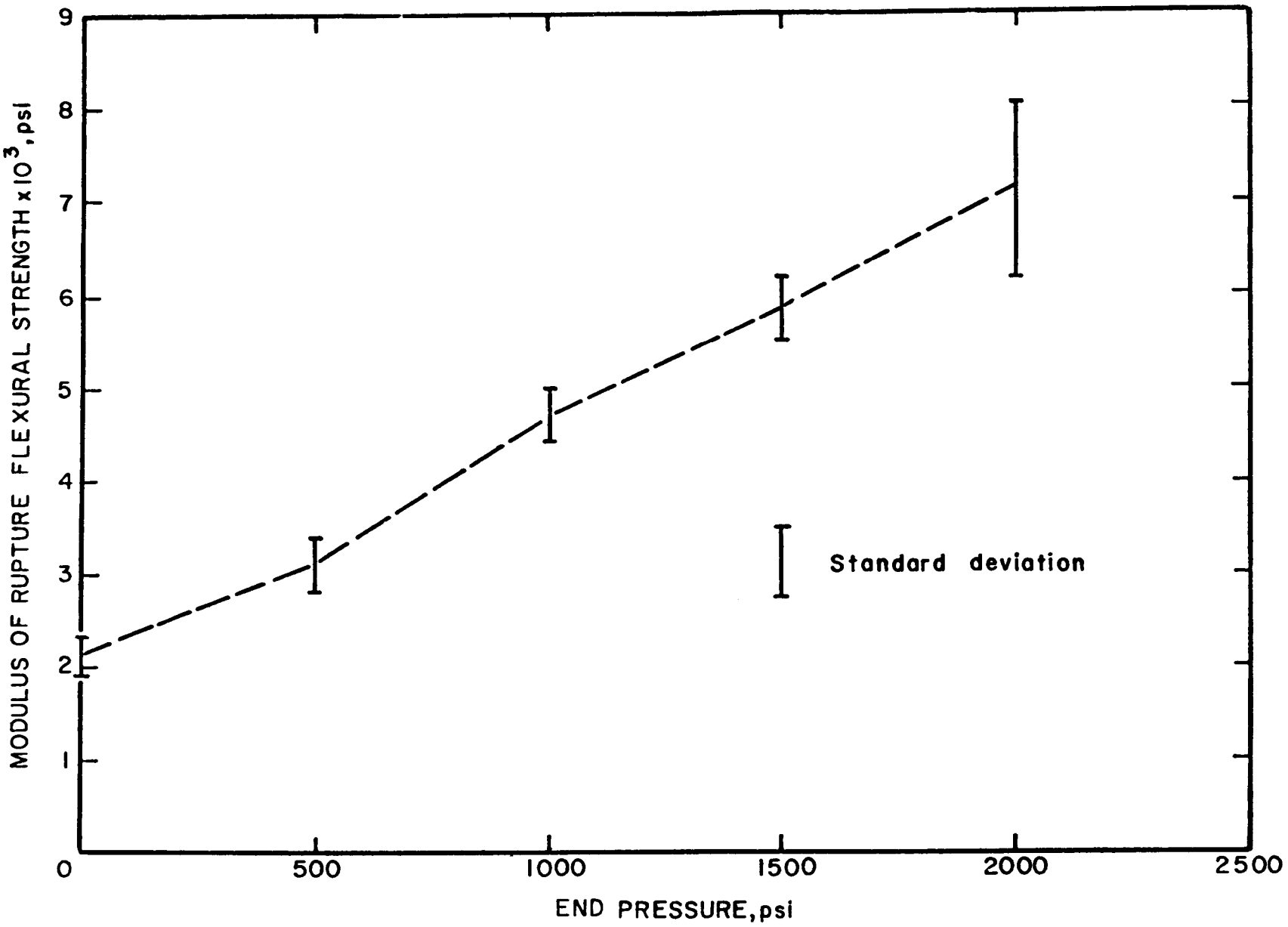


Figure 12 - Effects of end pressure on modulus of rupture.

(Brazilian). The ratio of the lowest value of the modulus of rupture to the lowest indirect tensile strength test is:

$$\frac{1949}{1009} = 1.93 \ .$$

This value is lower than the 2.4 value found by Akazawa (1) for concrete. The value thus obtained would appear to be site-specific. Higher values have been found by the authors at another site in the Piceance Creek Basin. One might use a value of two times the Brazilian strength test value as a good approximation of the modulus of rupture value. This value could be used until such time that mining operations permit the obtaining of horizontal cores so that regular modulus of rupture tests could be performed.

The verifiction of the shear strength value determined by the Mohr's envelope technique is made by the following formula (5):

$$\frac{C_o}{2} \left[(\mu^2 + 1)^{\frac{1}{2}} - \mu \right] = S_o$$

where C_o = uniaxial compressive strength,

μ = coefficient of internal friction,

S_o = shear strength.

Using the values of the above parameters from table 9, the following value is determined:

$$\frac{10931}{2} \left[(0.19337^2 + 1)^{\frac{1}{2}} - 0.19337 \right] = S_o$$

S_o = 4510 psi .

This value compares very favorably with the value of 4544 psi shear strength as presented in table 9.

SUMMARY

The physical property testing program resulted in sufficient information that multiple linear regression analyses could be performed to generate predictive equations relating yield in gpt to compressive strength, Young's modulus, Poisson's ratio and apparent specific gravity for the Mahogany zone. For the pillar in the air room above retort #6, some information was obtained with regard to strength and creep characteristics. All of this information is useful in preliminary mine design. Creep studies showed that closure should not be a problem in the air room.

Information was obtained with regard to the surface retorted material projected to be used as fill material. Results indicate that for the same particle size and for a given load, the compaction is greater for the shale with the greatest yield. Yields of 11, 25, and 37 gpt for a particle size of 3/16" in diameter resulted in percent compaction rates of 29.6, 43.1, and 50.2, respectively. Another conclusion drawn was that for the same yield, the larger the particle size, the greater will be the compaction for a given load. For a yield of 37 gpt and for particle sizes of 1¾" and 3/16", percent compaction rates of 85.5 and 50.2 were obtained.

End loading on modulus of rupture strength tests would indicate a 1250 psi strength increase with each end pressure increase of 500 psi. This information would be useful in the design procedure if the in situ stress analysis showed the existence of horizontal stresses of sufficient magnitude as to be a factor in the orientation, percent extraction ratio, and optimum sequence of mining.

A value of the modulus of rupture for a room horizon equal to twice the indirect tensile strength value was determined to be a first approximation.

The determination of these mechanical properties gives a firm basis for design if numerical methods are used for analysis. Distribution of shear stresses in the pillar and roof as well as prediction of the effect of mining on the ground surface could be analyzed by numerical methods.

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3. Horino, F. G. and M. L. Ellickson. A Method for Estimating Strength of Rock Containing Planes of Weakness. BuMines RI 7449, 1970, 29 pp.

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STATE OF STRESS

INTRODUCTION

In several retort structures of retort No. 6, stresses and stress distributions were measured using the Bureau of Mines' 3-component borehole gage and overcoring technique (2). The retort structures in which the stress distribution was determined included the upper air room pillar, sill pillar and the retort wall on the upper intermediate level. The measurements were taken before and after retort rubblization. The in situ state of stress was also determined at a site near the retort on the air room level.

IN SITU STRESS FIELD

The 3-dimensional stress field was determined at a site on the upper air room level approximately 250 feet north of retort 6. Figure 13 shows the site and the hole configuration used. The results of the stress calculations can be found on table 10. The table can be interpreted as follows: (For the x,y,z coordinate system, the +z axis is up, the +y axis is true north and the +x

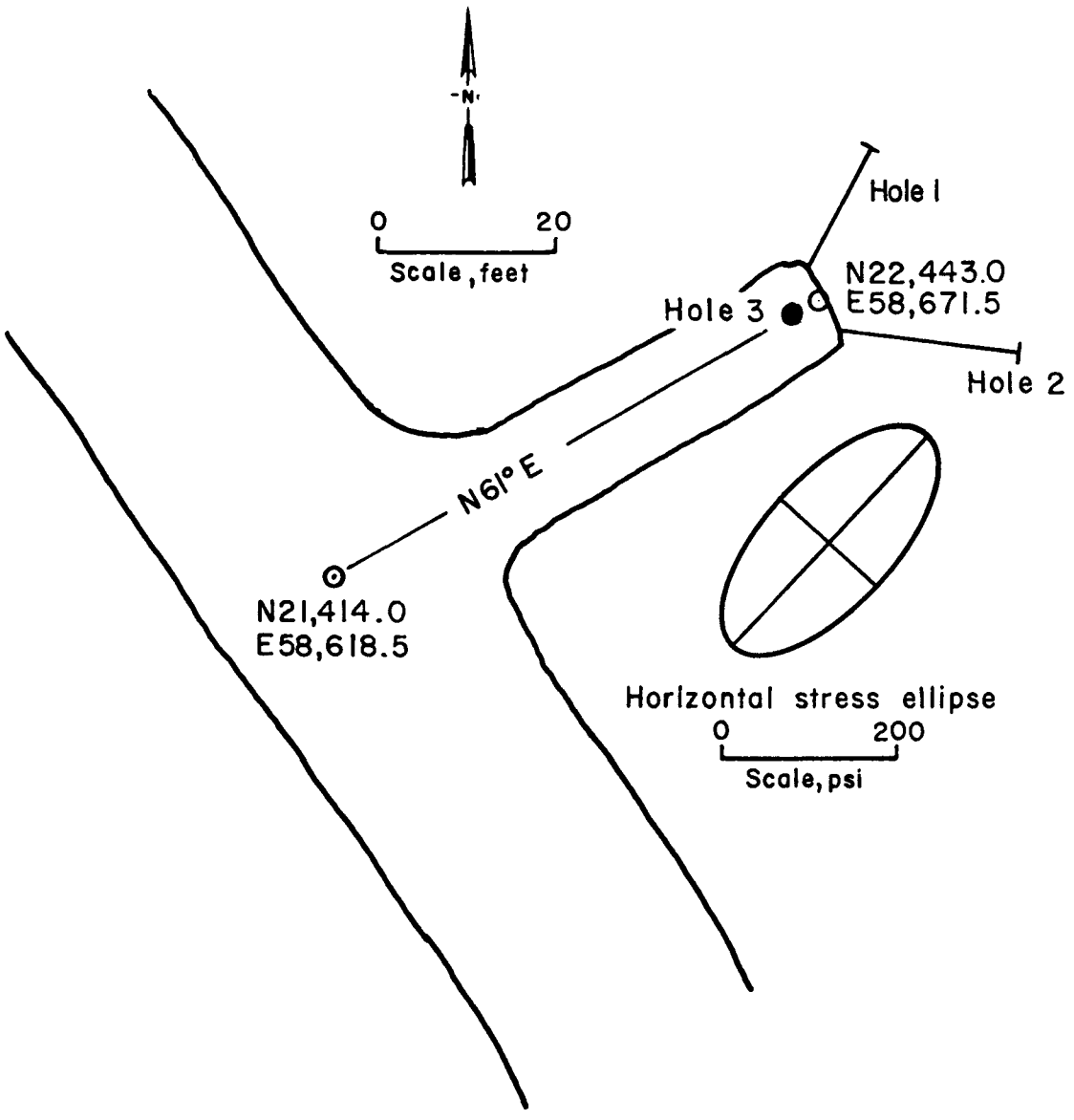


Figure 13 - Location of 3-dimensional stress site.

-STRESS ELLISIOD CALCULATIONS- Table 10

LOGAN WASH
24 DEFORMATION MEASUREMENTS

AVERAGE GROUND STRESS COMPONENTS
WITH RESPECT TO X,Y,Z COORDINATE SYSTEM-

SIGMA X =	-143. PSI	SIGMA Y =	-305. PSI	SIGMA Z =	-447. PSI
TAU XY =	-46. PSI	TAU YZ =	-23. PSI	TAU ZX =	-51. PSI

PRECISION OF DATA

DEFORMATION SUM OF SQUARES	=6.599664E-6
B1*G1+B2*G2+...+B6*G6	=5.948410354E-6
RESIDUAL SUM OF SQUARES	=6.512536464E-7
MULTIPULE CORRELATION COEFFIENT SQUARES	=0.901320181389
STANDARD DEVIATION OF THE FITTED DATA	=1.902124027E-4

STANDARD DEVIATION OF GROUND STRESS COMPONENTS-

SD (X) =	77. PSI	SD (Y) =	54. PSI	SD (Z) =	37. PSI
SD (XY) =	50. PSI	SD (YZ) =	38. PSI	SD (ZX) =	51. PSI

PRINCIPAL STESSES S1,S2, AND S3 AND THEIR DIRECTIONS-

S1 =	-125. PSI	BEARING =	103.29DEG.	INCLINATION =	82.15DEG.
S2 =	-462. PSI	BEARING =	43.17DEG.	INCLINATION =	164.52DEG.
S3 =	-309. PSI	BEARING =	11.43DEG.	INCLINATION =	76.75DEG.

STANDARD DEVIATION OF S1 = 66. PSI
STANDARD DEVIATION OF S2 = 48. PSI
STANDARD DEVIATION OF S3 = 55. PSI

axis is east. For the principal stresses and their directions, the bearing is measured clockwise from north with the inclination being measured as 0^{o} for vertically down, 90^{o} for horizontal and 180^{o} for vertically up.)[1] The range of Young's modulus and the Poisson's ratio used in the stress calculations along with the approximate yield at the site were:

Young's modulus	$1.8\text{-}3.7 \times 10^{6}$ psi
Poisson's ratio	0.33
Yield	16 gallons/ton

Figure 14 shows the projection of the principal stresses in space with respect to a north-south, east-west, vertical coordinate system.

In assessing the accuracy and reliability of the stress measurements, a comparison can be made between the measured vertical stress and that calculated from the overburden. The strata overlying the site are about 650 feet thick. Using a depth factor of 1 psi/foot, the vertical load should be 650 psi. If the effects of the topography are taken into account, the overburden load is reduced to about 575 psi (3). Comparing this value to the measured stress;

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[1] The sign convention used for stresses in this paper is that a negative sign represents a compressive stress.

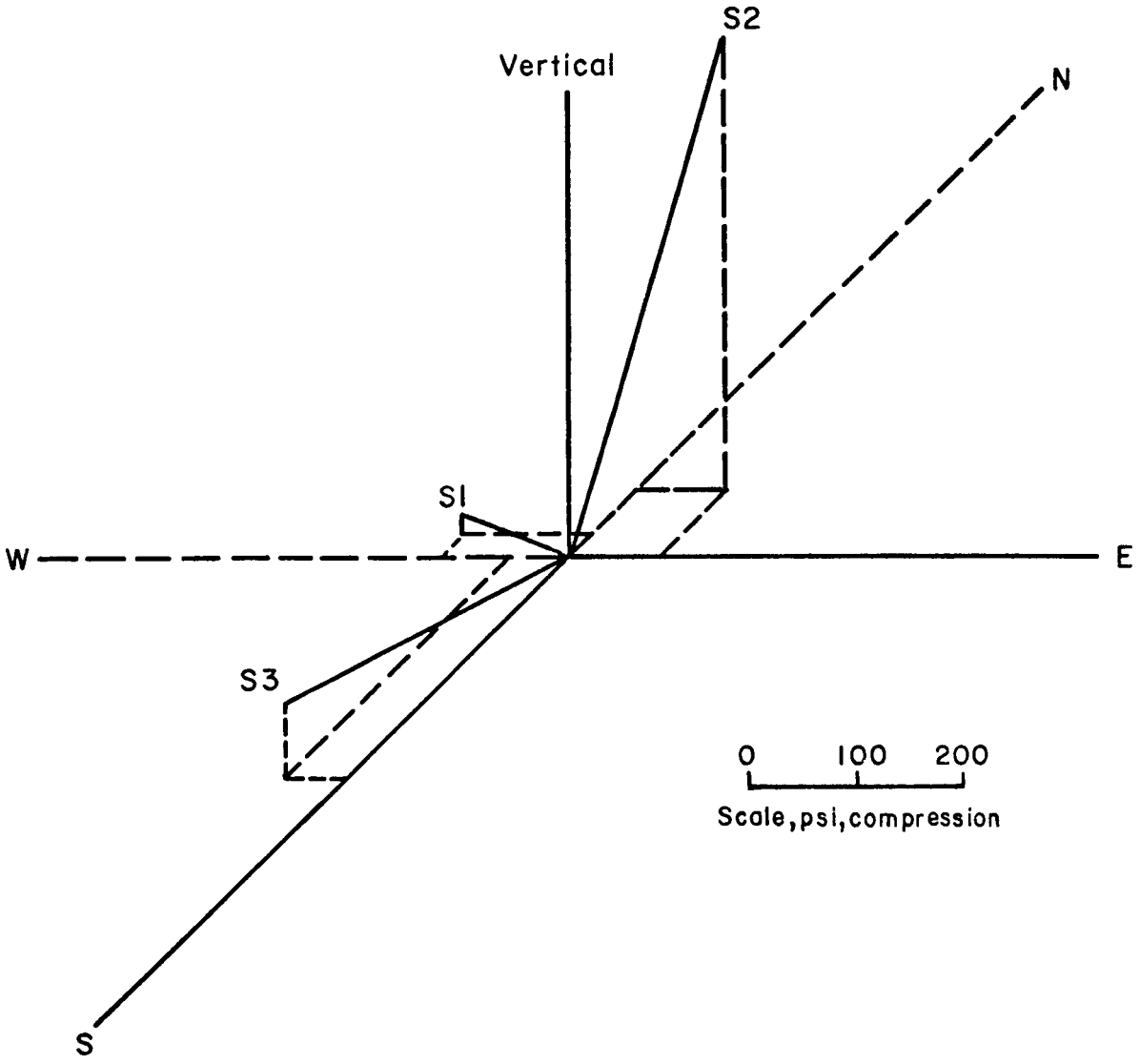


Figure 14 - Principal stresses in space.

calculated from overburden	-575 psi
measured (table 1)	-447 psi
difference	-128 psi

the measured stress is 23 percent lower than that expected. However, the difference is not large when considering the low stress values being measured, the assumptions made in calculating the vertical stress due to overburden and the complex topography encountered.

If the effects induced by a gravity load are subtracted from the measured horizontal stresses, the result will be the applied or excess horizontal stress. The measured stresses in the horizontal plane are (table 10):

σ_x = -143 psi

σ_y = -305 psi

τ_{xy} = - 46 psi

Rotating these to horizontal principal stresses:

P = -317 psi from N 15° E

Q = -131 psi from N 75° W

The horizontal stress due to gravity can be calculated from:

$$\sigma_h = \frac{\nu}{(1-\nu)} \sigma_v$$

where, $\sigma_v = \gamma h$

σ_v = vertical stress

σ_h = horizontal stress

γ = density of overburden

h = depth of overburden

and ν = Poisson's ratio

Using the measured vertical stress of 447 psi instead of that calculated from the depth and density of the overburden because of the variable topography and a Poisson's ratio of .33 the horizontal gravity induced load at the site is:

$$\sigma_h = \frac{.33}{(1-.33)} \quad (-447)$$

$$\sigma_h = -224 \text{ psi}$$

Subtracting this from the measured horizontal stresses the applied or excess stresses are:

P' = -93 psi from N15°E

Q' = +93 psi from N75°W

It would appear that the applied or excess stress in the N75°W direction is a tensional force. However, this is not the case. The applied stress in that direction is probably zero with the horizontal stress due to overburden having been in part relieved by lack of confinement caused by the formation of Logan Wash. In fact there may be no actual applied or excess stresses at the site due to the outcropping of the formation and that the measured stresses are entirely gravity induced.

AIR ROOM PILLAR

The locations of the overcoring holes used for the measurement of the air room pillar stress distribution are shown in figure 15. The pillar where the measurements were taken was 18 feet wide by 14 feet high with the holes being drilled at the mid-height of the pillar and to a depth just beyond the pillar center.

The pre and postblast stress profiles are shown in figures 16 and 17 respectively. The preblast distribution of the vertical stress is fairly uniform, as would be expected in a small pillar. For the horizontal stress, the first two measurements are high but this was due to blast factures that openned during overcoring which affected some of the deformation readings. The average preblast stresses within the pillar are (1):

$$P = -1486 \text{ psi}$$

$$Q = -642 \text{ psi}$$

The maximum compressive stress P is inclined 8° off vertical toward the northwest.

The principal stresses can be rotated to their vertical and horizontal components. These stresses are·

$$\sigma_v = -1370 \text{ psi}$$

$$\sigma_h = -645 \text{ psi}$$

$$\tau_{vh} = 106 \text{ psi}$$

where,

σ_v = vertical stress

σ_h = horizontal stress

τ_{vh} = shear stress

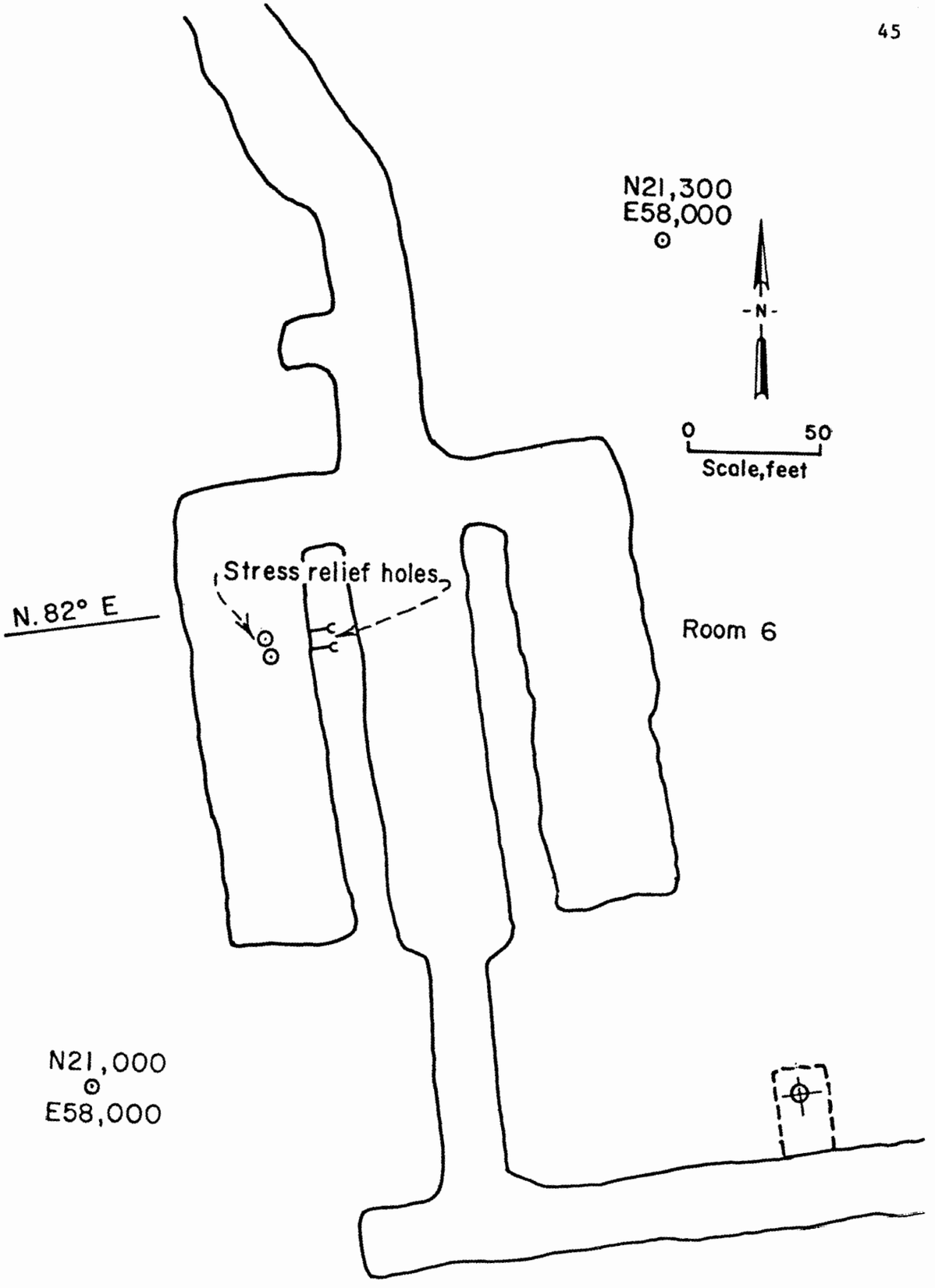


Figure 15 - Location of stress relief holes air room level.

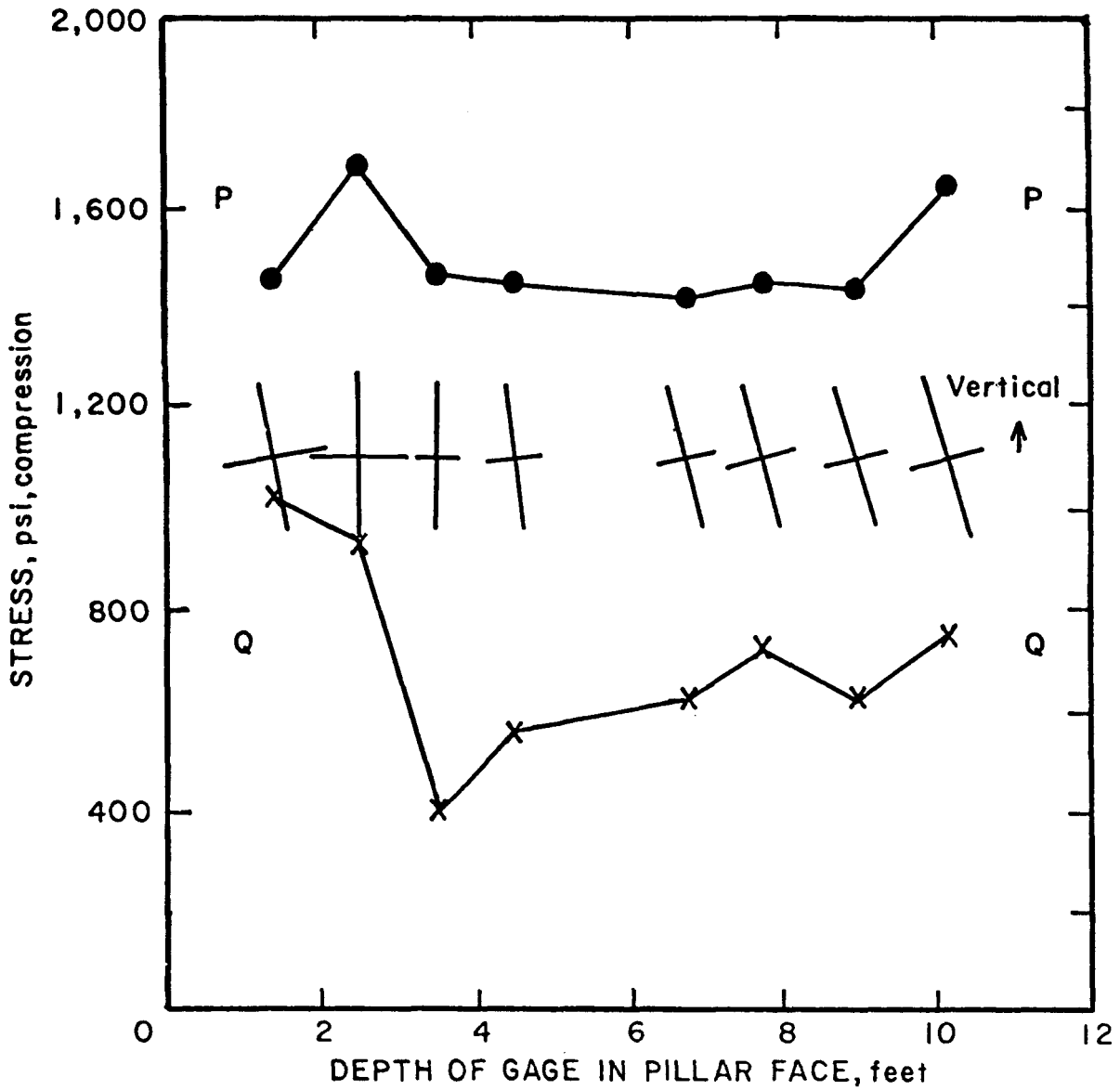


Figure 16 - Upper air room pillar stress profile (preblast).

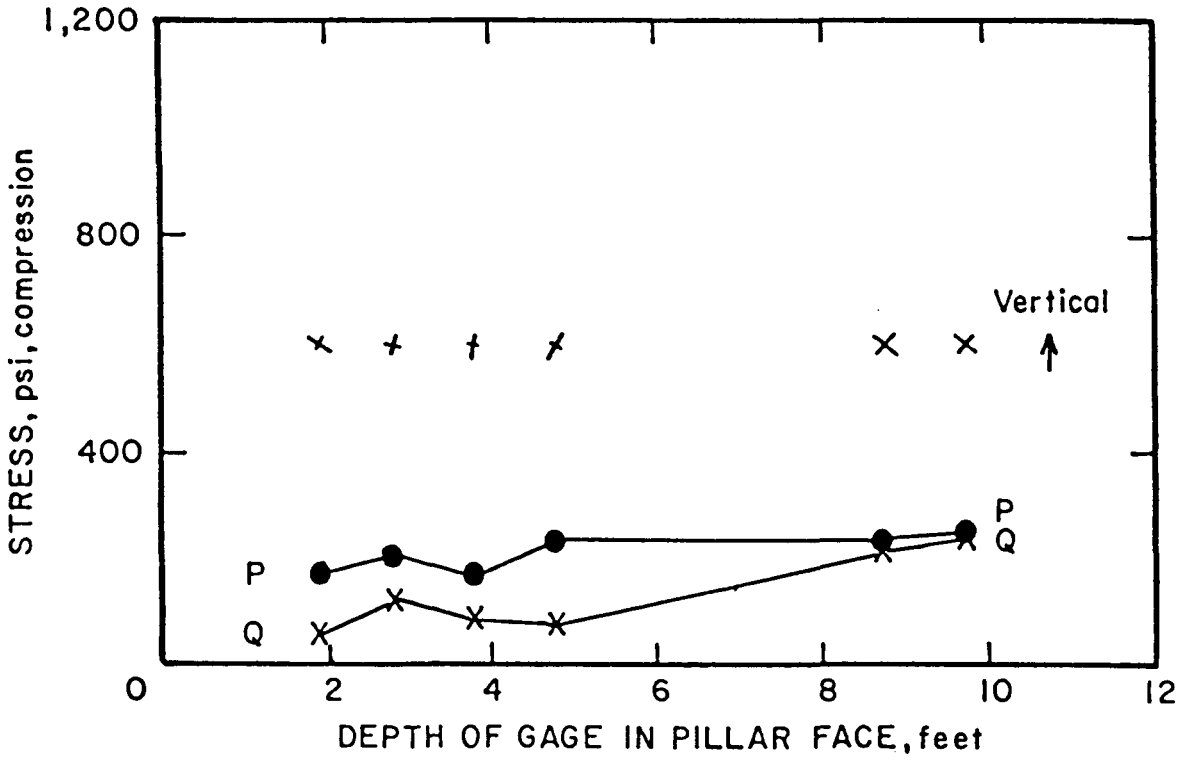


Figure 17 - Air room level stress profile (postblast).

Using a tributory area method to calculate what load might be expected on the air room pillar, based on the room spans and pillar width and with an initial vertical stress of 447 psi the stress on the pillar should be 1540 psi. The difference from the measured vertical stress is probably the result of the retort walls being stiffer and carrying more of the load. The measured stresses seem quite compatible with what might be expected.

The postblast stress distribution in figure 17 shows a significant drop for both stress components when compared to the preblast stress results. The average postblast stresses are:

$$P = -230 \text{ psi}$$

$$Q = -172 \text{ psi.}$$

With P being inclined 45° from vertical toward the northeast. However, since the stresses are so low and nearly equal, the direction is not very important. Again rotating these stresses to horizontal and vertical components:

$$\sigma_v = -201 \text{ psi}$$

$$\sigma_h = -200 \text{ psi}$$

$$\tau_{vh} = -29 \text{ psi.}$$

The horizontal stress has about the same magnitude as that measured at the 3-dimensional site. The major portion of the vertical stress has been relieved due to the loss of the underlying support structure from blasting causing the sill pillar to sag. Changes in the horizontal and vertical stress due to the retort rubblization can then be calculated:

252 $$\Delta\sigma_h = (-657 - -200) = -457 \text{ psi}$$

$$\Delta\sigma_v = (-1370 - -201) = -1169 \text{ psi}$$

where,

$\Delta\sigma_h$ = change in horizontal stress

$\Delta\sigma_v$ = change in vertical stress.

From the change in the horizontal and vertical stress it is possible to calculate a mass Poisson's ratio. However, there is a problem in that the stress change in the direction perpendicular to the plane in which the stresses were measured is not known. The condition in the pillar lies between plane strain with total confinement of the pillar across the short dimension to plane stress. If total confinement is assumed then the Poisson's ratio would be;

$$\nu = \frac{(\Delta\sigma_h / \Delta\sigma_v)}{(1 + \frac{\Delta\sigma_h}{\Delta\sigma_v})}$$

then

$$\nu = \frac{\frac{-457}{-1169}}{(1 + \frac{-457}{-1169})} = .28$$

If the plane stress condition exists where there is no change in stress perpendicular to the length of the pillar the Poisson's ratio would be:

$$\nu = \frac{\Delta\sigma_h}{\Delta\sigma_v}$$

then

$$\nu = \frac{-457}{-1169} = .39$$

The Posson's ratio of the upper air room pillar should be between .28 and .39.

SILL PILLAR

Stress relief measurements were taken to a depth of about 20 feet vertically down in the sill pillar from the air room level. This was done both before and again after the retort was rubblized. The location of the overcoring holes used is shown in figure 15. In general, much of the variability of the calculated stresses and the deformation measurements observed was caused by low stress values being measured, to poor recovery of core of suitable length which resulted in an inability to determine the elastic constants for many individual stress reliefs, and to horizontal and vertical planes of weakness which caused poor results for many overcores. Because of blast damage, no measurements were obtained above a depth of 6 feet.

The preblast stress profile is shown in figure 18. This should essentially be a measurement of the in situ horizontal stress because no sill pillar had been formed. The measurements from 17-20 feet should be at least affected by the upper air room and therefore be comparable to the stress determined at the 3-dimensional stress site. The average stresses of these 3 measurements are:

P = -357 psi from N 13° E

Q = -205 psi from N 77° W.

They are in good agreement with the 3-dimensional results. The high stress value at 7 feet was probably due to a plane of weakness near the borehole gage pistons on which the core broke upon retrieval although the measurements for the stress relief were very good. For all measurements the average preblast stresses in the still pillar are:

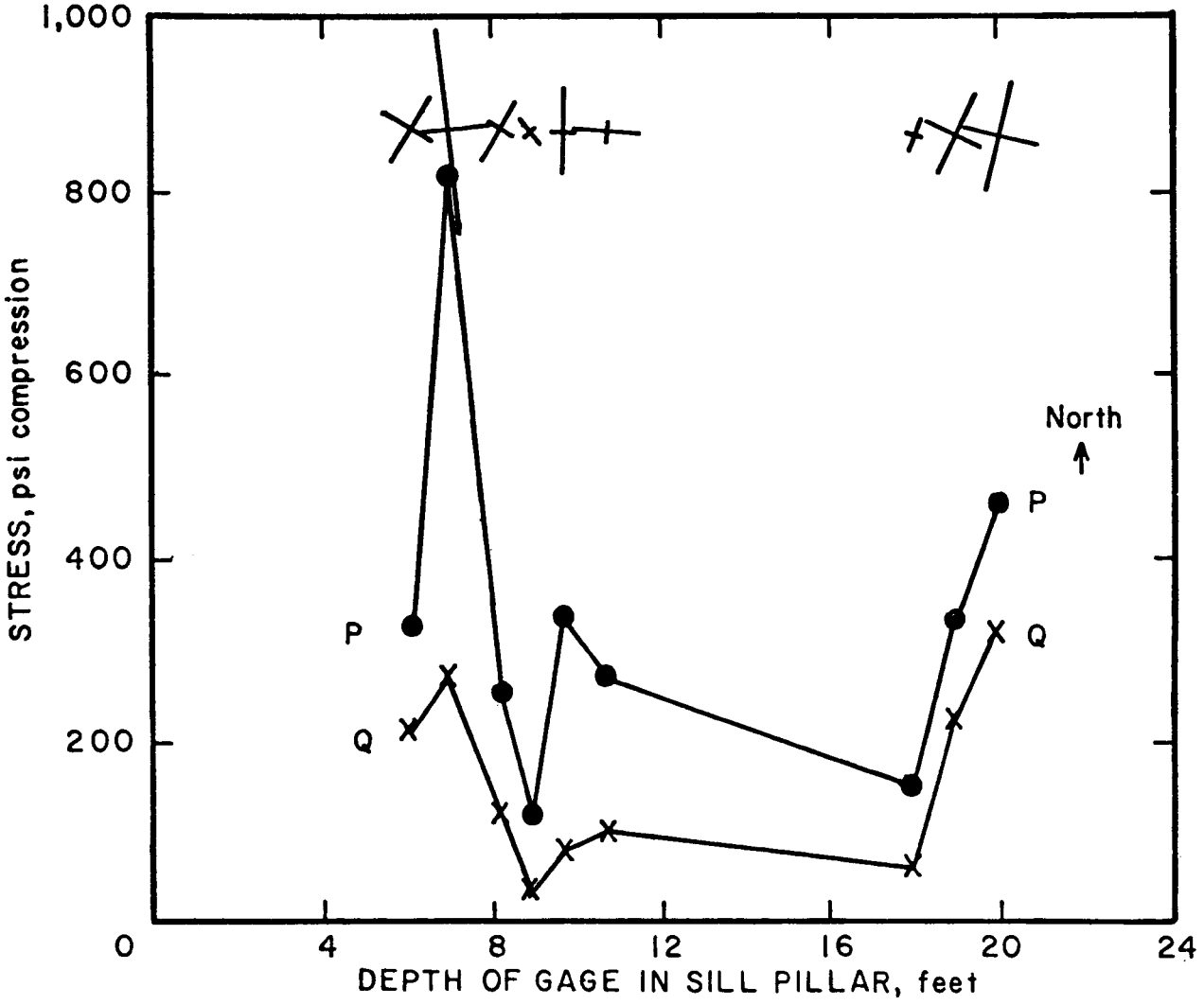


Figure 18 - Sillpillar stress profile (preblast).

P = -326 psi from N 3° E

Q = -226 psi from N 87° W .

Those results are still in close agreement with those measured at the 3-dimensional site.

The postblast stress distribution is shown in figure 19. The stresses nearest the top of the retort are low and, in fact, some are tensional stresses. The stresses do increase slightly, but then stay fairly uniform until the last 2 measurements when there was a large increase in the stress. Since there is evidence that the sill pillar has sagged and with the trend in the magnitude of the stresses to increase with depth the pillar may be acting as a beam in bending. It has been suggested that the sill pillar may be responding as multipul beams under a gravity lead with slip planes being formed along partings. This could be very possible because occasional partings and breaks in the overcores were observed. However, it is difficult to tell just from the stress measurements if this is occurring. The post blast stress profile could be interpreted as if 2 or 3 separate beams had been formed. But much of this variation can be explained by reasons previously mentioned such as, the low stress values being measured, the poor recovery of core of suitable length and to vertical and horizontal plans of weakness. What was definitely seen was that the stresses near the top of the sill were in tension with the maximum compressive stresses deepest in the sill. The average of all the post blast stress measurements is:

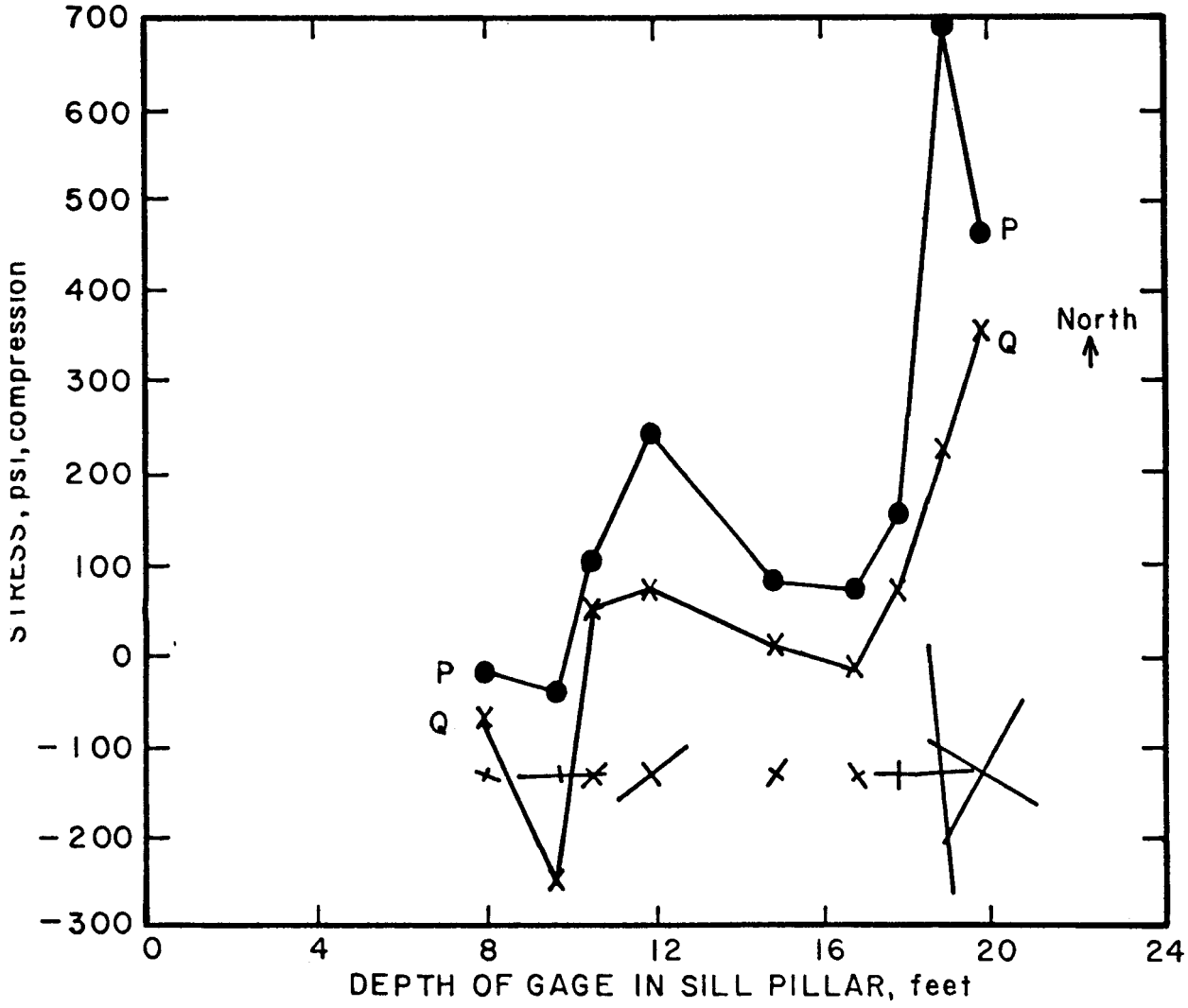


Figure 19 - Sillpillar stress profile (postblast).

P = -102 psi from N 10° W

Q = -157 psi from N 80° E

The post blast stresses are lower and have been rotated from the pre-blast results.

RETORT WALL PILLAR

The retort wall stress distribution was determined on the upper intermediate level, again prior to and after retort rubblization. The site where the measurements were taken was just above the A-groove and has a yield of about 18 gallons/ton. Figure 20 shows the location of the overcoring holes with respect to the retort. Measurements were started at approximately 35 feet from the retort and were continued until the blast damage zone was reached. Drilling was then continued until the position of the retort boundary was established. What appeared to be blast damage was initially observed at about 8 feet from the retort boundary. However, for the next 6 feet solid EX core was recovered. At that point the core was highly fractured for a further distance of about 3 feet. Circulation of water was then lost and this was where the retort boundary was selected. At the time of the preblast stress measurement the upper intermediate level was developed as shown in figure 20. Therefore, a stress concentration would be expected in the retort wall.

The preblast stress distribution is shown in figure 21 along with the location of the retort wall. There is no increase in stress toward the retort wall. This may be due to blast damage caused by mining the room, to the loads being distributed fairly evenly over a large area around the retort of to the yielding nature of the oil shale. The average retort wall stresses are:

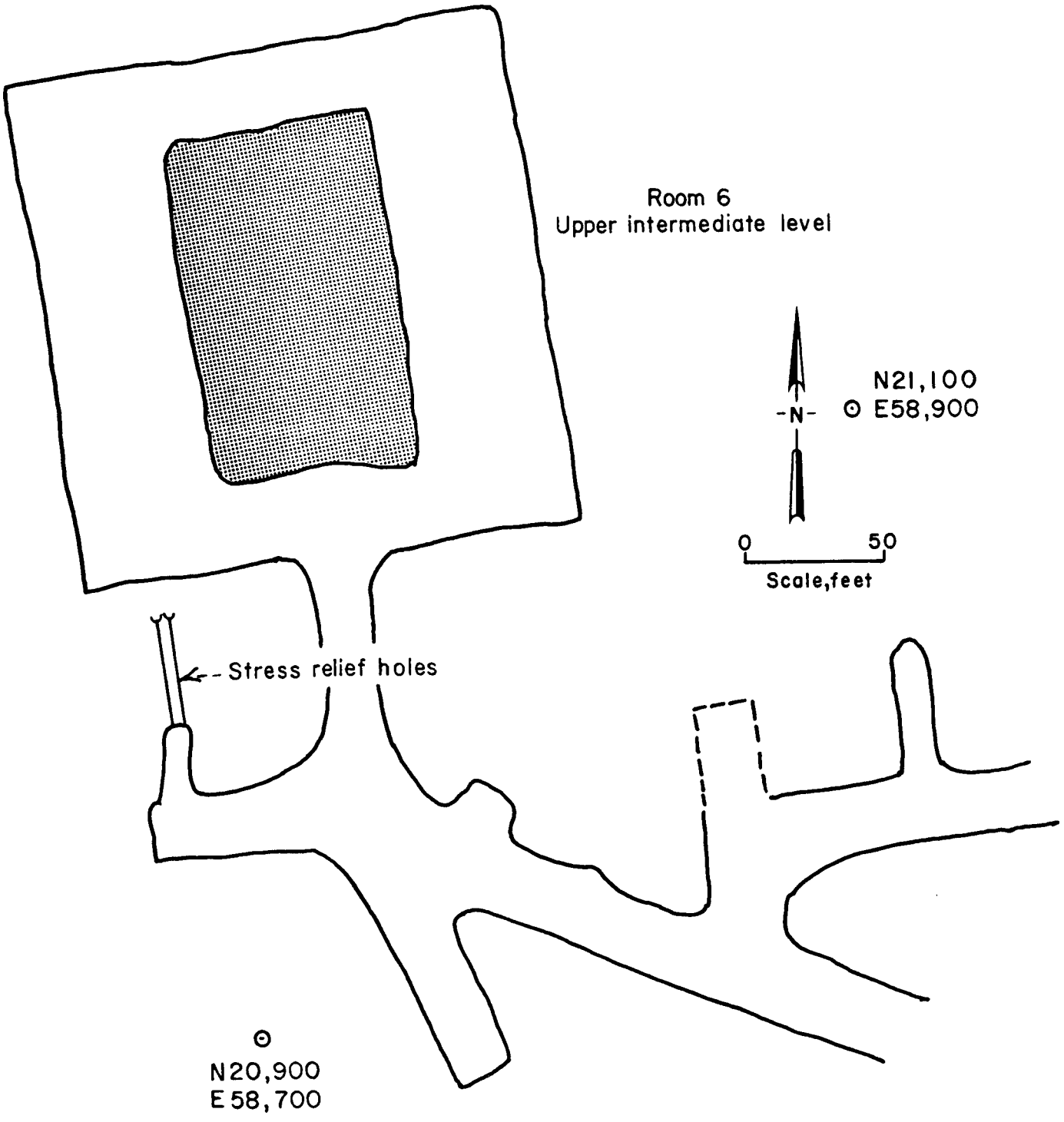


Figure 20 - Location of stress relief holes in retort wall.

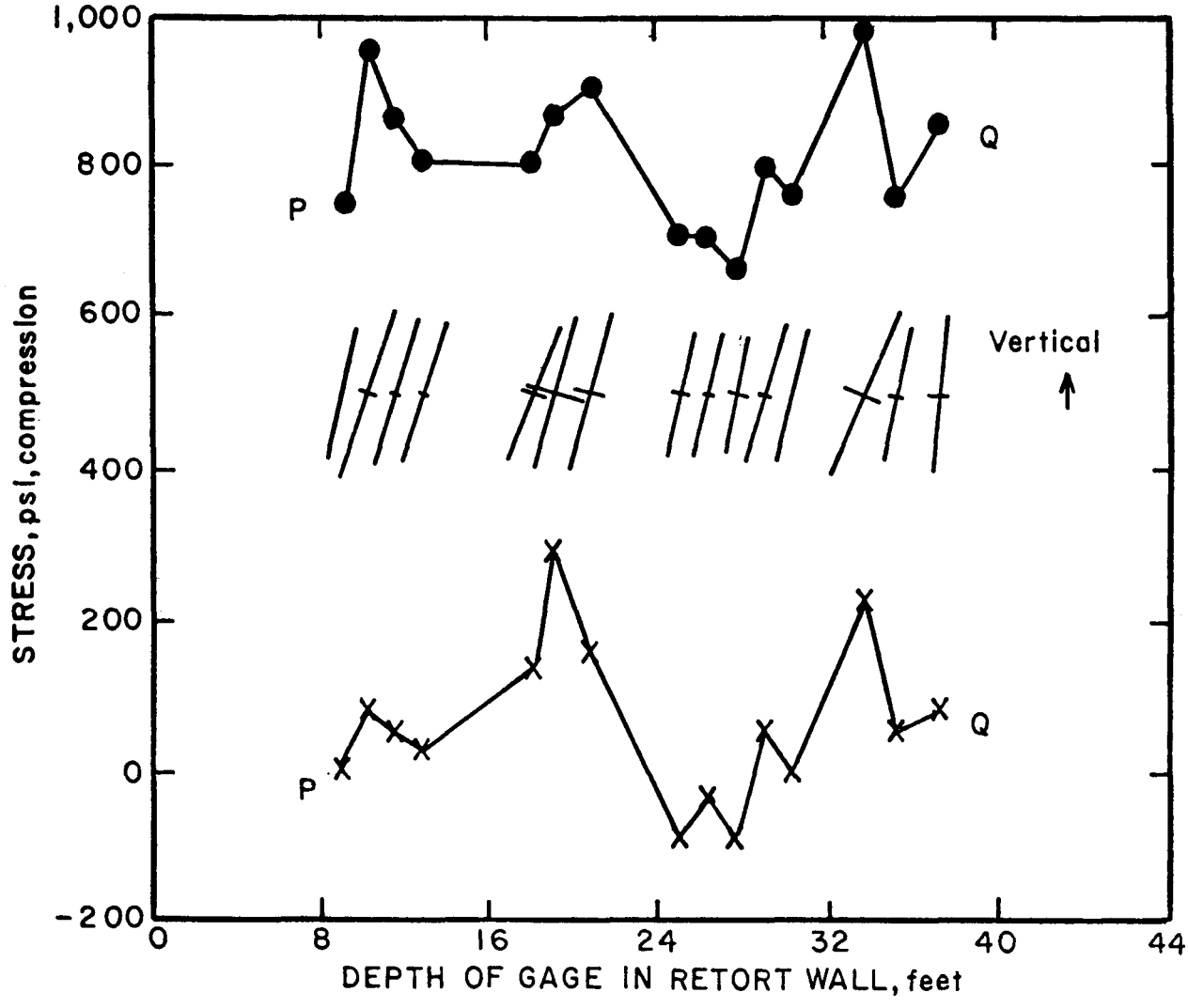


Figure 21 - Retort wall stress profile (preblast).

$$P = -806 \text{ psi}$$

$$Q = -67 \text{ psi}$$

with P being inclined from vertical 15° toward the northeast. In terms of the vertical and horizontal components, the stresses are:

$$\sigma_v = -757 \text{ psi}$$

$$\sigma_h = -114 \text{ psi}$$

$$\tau_{vh} = -185 \text{ psi}$$

The premining vertical load from overburden should be about 600 psi. The average measured retort wall stress is 157 psi more than this. If the increase in stress due to the mining of the room is evenly distributed over a zone 75 to 100 feet wide around the retort, the increase in the vertical stress over this zone would be 150 to 200 psi. This could account for the observed stress values and distribution. However, the 600 psi overburden stress is only an estimate, and the extent of the zone of possible stress redistribution is a guess based on measurements taken over a 30-foot span in the retort wall.

The postblast stress profile is shown in figure 22. Again there is no trend to the vertical stresses. The horizontal stresses do show an increase beyond 20 feet although the horizontal stresses are quite variable. The average stresses in the retort wall are:

$$P = -700 \text{ psi}$$

$$Q = -223 \text{ psi}$$

with P being inclined 10° off vertical toward the northeast. Again rotating to horizontal and vertical components;

$$\sigma_v = -684 \text{ psi}$$

$$\sigma_h = -239 \text{ psi}$$

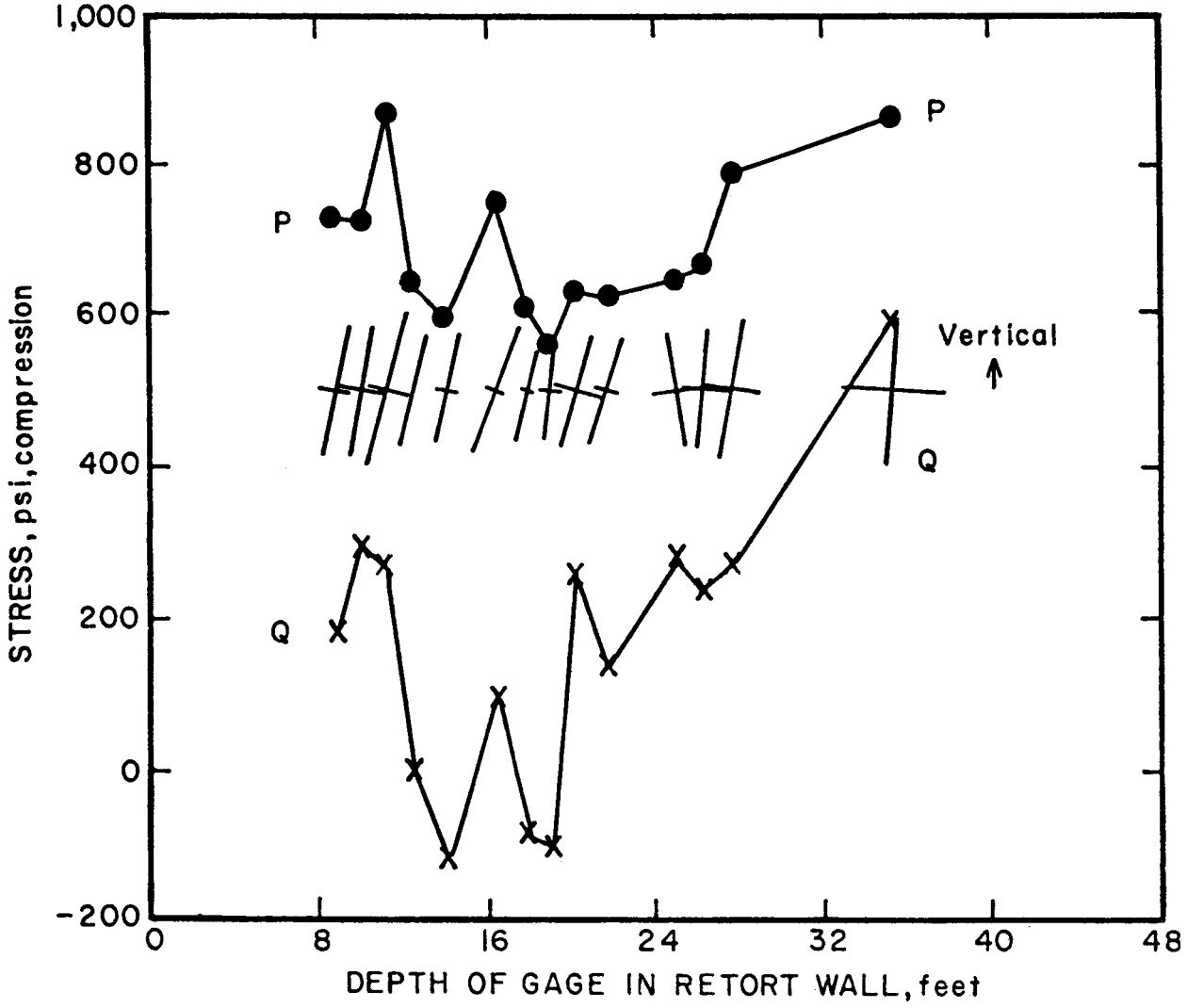


Figure 22 - Retort wall stress profile (postblast).

Comparing these to the pre-blast stresses the vertical stress has decreased while the horizontal stress has increased. Because the upper intermediate level room was already developed,there was not a large change in the stresses upon rubblization. The small drop in the vertical stress is due in part to the horizontal stress arching around the retort causing a relaxation of the vertical stress and to the fact that the pre and post blast overcoring holes were in a different position with respect to the room or retort. The pre blast measurements were made near the bottom of the upper intermediate level room while the post blast measurements were made toward the middle of the retort. The increase in the horizontal stress was probably caused by the removal of the sill pillar between the upper and lower intermediate levels, which resulted in the horizontal stress normal to the overcoring hole being concentrated in the retort wall.

SUMMARY

The effects of rubblization on the stress distribution in various retort structures of retort No. 6 were studied. Stress measurements were taken before and after rubblization in the air room pillar, sill pillar and retortwall. The insitu stress field was also determined near the retort prior to rubblization.

The 3-dimensional state of stress was measured on the upper air room level near retort No. 6. The vertical stress at the site was nearly equal to that calculated from the overburden. The horizontal stresses were low and appear to be primarily gravity induced rather than tectonic due to the formation outcropping.

The largest change in stress occurred in the air room pillar where the vertical stress was in large part relieved due to the sagging of the sill pillar. From the pre and post blast measurements a range of the Poisson's ratio for the pillar was calculated. In the sill pillar the pre-blast stresses were nearly the same as the horizontal stresses measured at the 3-dimensional stress site. The post blast measurements indicate that the sill is acting as a beam in bending. Multiple beams in the sill pillar may also have been formed but this is difficult to tell just from the measurements.

Finally in the retort wall there was little change between the pre and post blast stresses. This was the result of the upper intermediate level room already having been mined prior to the pre blast stress measurements being made. The changes that did occur were caused by the horizontal stresses arching and concentrating around the retort.

REFERENCES

1. Duvall, W. I., J. R. Aggson. Lease Squares Calculation of Horizontal Stresses from More Than Three Diametral Deformations in Vertical Boreholes. BuMines RI 7894, 1974, 12 pp.

2. Hooker, V. E., D. L. Bickel. Overcoring Equipment and Techniques Used in Rock Stress Determination. BuMines IC 8618, 1974, 32 pp.

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STRESS - TEMPERATURE

INTRODUCTION

The main objective of this research was to evaluate stress-change-measuring instrumentation used over a long (6 months or more) period of time and at elevated temperature, and to determine the best placement location of such type of instrumentation around a retort.

Two types of instrumentation were used: 1) A three-component borehole deformation gage designed to withstand 400°F (205°C) and 2) A vibrating wire stressmeter (gage) also designed to operate at 400°F. All the instrumentation was located outside the southwest corner of the retort on the upper intermediate level. Vibrating wire stressmeters were positioned 10 ft., 11 ft., 14 ft., and 15 ft. from the retort boundary and the borehole deformation gage was positioned at the 15 foot depth.

APPROACH

Figure 23 is a plot of coefficient of thermal expansion versus gallons per ton, for temperatures below 392°F, from data obtained by the Colorado School of Mines (1). Using this data and Young's modulus from figure 6 and Poisson's ratio from figure 7, anticipated stress changes were calculated from this equation:

$$\sigma_c = \frac{\alpha E (\Delta T)}{1-\nu}$$

where

σ_c = change in stress

α = thermal coefficient of expansion

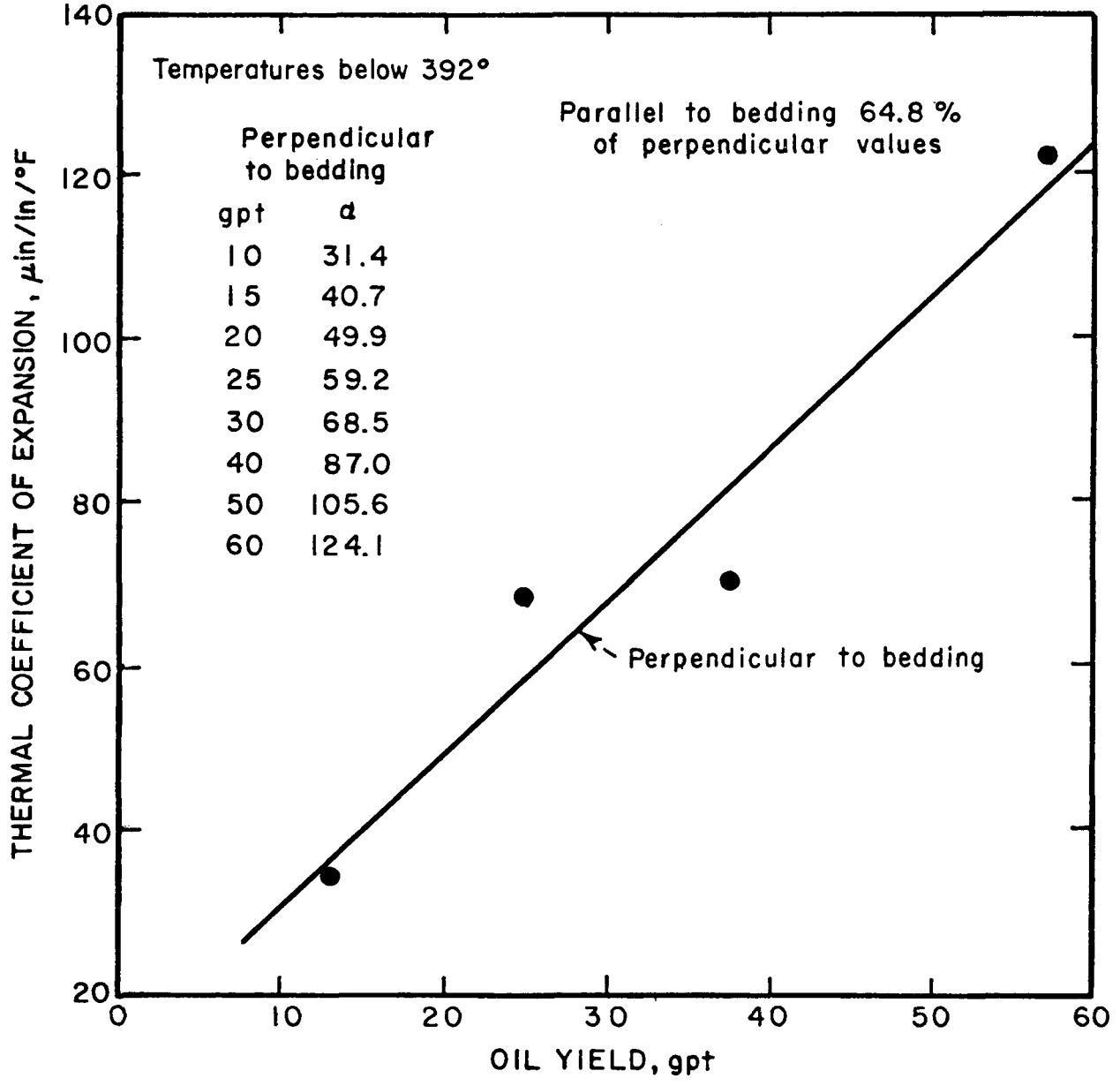


Figure 23 - Thermal coefficient of expansion versus yield.

E = Young's modulus

ν = Poisson's ratio

ΔT = temperature change

The data in the Colorado School of Mines report indicate a strong difference between the thermal coefficients parallel to the bedding and perpendicular to the bedding. Although only one grade of oil yield was determined parallel to bedding, until additional data are obtained this percentage variation was used to calculate anticipated stress changes parallel to the bedding and perpendicular to the bedding. These curves are shown in figure 24.

RESULTS

Three of the 4 vibrating wire stressmeters failed internally (not due to installation procedure) shortly after installation on June 7, 1978. Information from the remaining stressmeter was in the vertical direction (perpendicular to the bedding) and was considered reliable up to December 15, 1978 about 3 months after the burn started. The initial meter reading for this gage was 1979. The meter reading on December 15th was 2226 a difference of 247 readout units. Young's modulus of this rock in the vertical direction was determined to be 2.8×10^6 psi. From the following equation the uniaxial stress change is determined.

$$\sigma_r = \frac{\left[\frac{422400}{T_o}\right]^2 \left[1 - \left(\frac{T_o}{T}\right)^2\right]}{11.4 - 0.66 \times 10^{-6} E_r} \qquad (1)$$

where

T_o = initial meter reading

T = later meter reading

E_r = Young's modulus of the rock

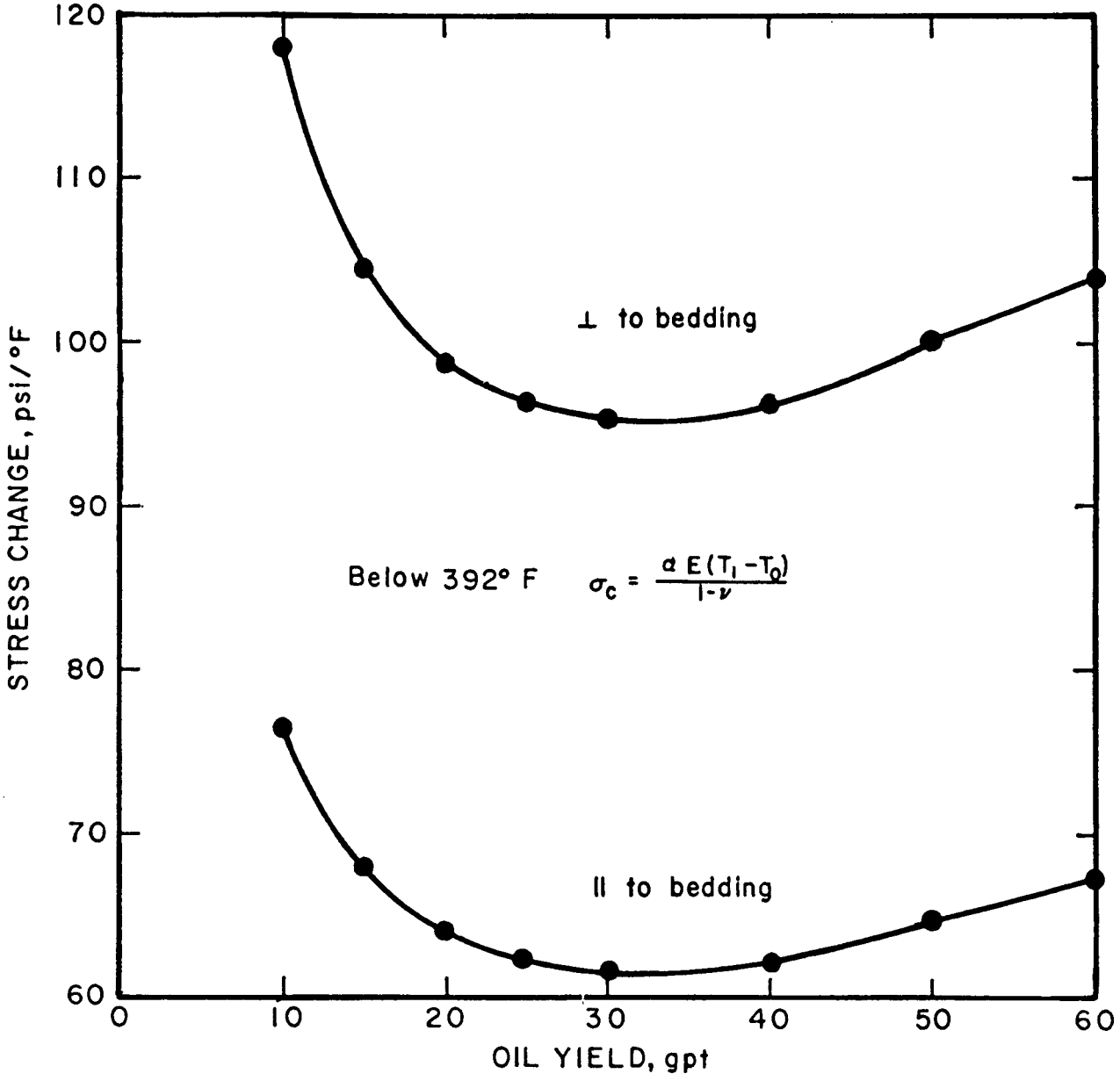


Figure 24 - Stress changes, perpendicular and parallel to bedding, created by temperature change for various oil yields.

σ_r = change in rock stress for uniaxial plane stress conditions only

substituting:

$$\sigma_r = 1000 \text{ psi}$$

Since the stressmeter is within a biaxial stress field this uniaxial stress value must be converted to a biaxial stress change.

The equations developed to convert this uniaxial stress to a biaxial stress are as follows:

$$S_x = \frac{9}{8} S'_x + \frac{3}{8} S'_y$$

$$S_y = \frac{3}{8} S'_x + \frac{9}{8} S'_y \qquad (2)$$

where S'_x is the uniaxal stress at 0°

where S'_y is the uniaxal stress at 90°

The derivation of these equations are found in a paper by Wilbur I. Duvall (2) and the instruction manual provided by the manufacturer of the stressmeter Irad Gage Inc.

Since the horizontal stressmeter failed internally, only information was obtained from the vertical stressmeter. To satisfy the biaxial stress condition the missing S'_x data is set equal to S'_y in equation (2). The result calculates to 3/2

$$3/2 \times 1000 \text{ psi} = 1500 \text{ psi}$$

Laboratory tests performed by the Bureau has indicated when using the "soft rock" wedging system in oil shale the resulting readout did

not correctly represent the stress change when using equation (1). These biaxials tests showed that the stressmeter orientated perpendicular to the bedding responded differently than the stressmeter oriented parallel to the bedding. The gage oriented perpendicular to the bedding recorded a stress change that was low by 33%. If the biaxial stress change of 1500 psi is corrected by 33%, the resulting stress change becomes 1995 psi. This stressmeter was measuring in 17 gpt oil shale. The temperature increase recorded for this same period of time (June 7, 1978 to December 15, 1978) was 27°F. Using 101.4 psi/°F temperature change (see figure 24 top curve) the calculated stress change due to thermal expansion is 2738 psi. As the temperature increases, the open seams and fractures (normal and blasting) had to close before the stressmeter detected any stress change. It can be said, that the measured stress change of approximately 1995 psi is lower than the calculated 2738 psi stress increase due to the thermal expansion of the rock which should be expected.

The bottom curve in figure 24 shows that for a stressmeter oriented parallel to the bedding 65 psi/°F temperature change can be used for all oil grades ranging from 15 to 60 gpt in the temperature range up to 392°F.

It is recommended to biaxially test (when under an in situ biaxial condition) the vibrating wire stressmeter in the same rock type where the stressmeters are installed, to use this calibration factor instead of using the uniaxial stress equation (1) to more closely determine the correct stress change. When calibrating the vibrating wire stressmeter, it should be oriented in the same direction and biased to the same value as the in situ stressmeter.

The data from this one remaining stressmeter from December 15, 1978 until March 9, 1979 did give alternate high and low readings with each successive reading. This indicates a leak through the seal causing a short, therefore, the data is considered questionable. The April 6th reading shows the remaining stressmeter has also failed internally.

The two internal problems with this type of gage are the brass seals on each end of the steel cylinder leaking either water or gases, and the vibrating wire becomes loose from its anchor. These problems were not known to us at the time of installation. However, the manufacturer of the vibrating wire stressmeter indicates that these problems have been remedied.

The three-component borehole gage worked until the December 29th readings when component 2 shorted. At that time the calculated stress was less than the stress calculated from the vibrating wire stressmeter. See table 11. However, the stresses determined from the borehole gage deformation readings must be corrected for any zero shift, and for the thermal expansion of the borehole gage. The zero shift, however, will not be known until completion of the project when the gage will be recovered and tested. The direction of the maximum stress (calculated on December 29, 1978) was 35° above the horizontal. Measurements were taken from the remaining two components of the borehole gage until July 27, 1979, when the readings started to fluctuate. From this date the readings cannot be considered reliable.

Table 11. - Calculated secondary principle stresses determined from the three-component borehole gage.*

Date	Component 1 Reading 90°(Vert.)	Deformation μ"/in.	Component 2 Reading 150°	Deformation μ"/in.	Component 3 Reading 30°	Deformation μ"/in.	P psi	Q psi	θ degree
6/27/78	12148	Initial Reading	13914	Initial Reading	11911	Initial Reading	--	--	--
7-27-78	12122	25	13956	-40	11917	-6	-27	13	-74
8/25/78	12048	96	13885	28	11908	3	16	75	82
10/11/78	11943	197	13905	9	11932	-20	-6	139	86
11/1/78	12015	128	13851	60	11951	-38	2	105	72
11/16/78	12247	-95	14030	-111	12002	-86	-112	-96	-51
12/1/78	12437	-277	14067	-147	12141	-219	-269	-189	17
12/15/78	12560	-396	14282	-353	12258	-330	-403	-364	-10
12/29/78	12739	-567	14716	-770	12455	-517	-742	-577	-55

*Note: A minus value of deformation or stress indicates compression. A positive θ value is the angle from P to U_1 measured counter clockwise.

While the borehole gage was operative, the measurements showed that, as the burning started its downward movement, the stress in the vertical direction increased faster than the stress in the horizontal direction. As the burn front neared the level of the borehole gage, the horizontal stress increased faster than the vertical stress. Then as the burn front moved down away from the level of the gages, the stress in the vertical direction was again increasing faster than the stress in the horizontal direction. This reflects the stress increase due to thermal expansion of the rock.

The increase in temperature has to be known and accounted for to correctly determine the stresses. Therefore temperatures were recorded from thermistors located in the vibrating wire stressmeter and from the vibrating wire itself. Figure 25 shows the temperature increases measured using the vibrating wires at 10 ft., 11 ft., 14 ft., and 15 ft., from the retort boundary. The vibrating wire stressmeter at the 10-foot depth failed in December of 1979 and in January 1980 the thermistor failed resulting in loss of temperature data at this gage location.

The vertical movement of the burn front was observed from the instrumentation on this one level, however, the rate of burn could not be accurately defined. The precise location of the burn front during the burning at this retort were not made known to us. It would be desirable to install instruments on two levels.

Both the 4-D borehole deformation gage and the vibrating wire stressmeter are constructed with material that will withstand 400°F. During the burning of retort 6, the highest temperature recorded from the gage wire and the thermistor located 10 feet from the retort boundary was 361°F. This 10-foot defines the distance (within one foot) that these instruments can be installed from the retort boundary. The highest temperature reached at the 15-foot depth was 273°F. The difference in temperature between the 10-foot and 15-foot depth was 88°F (a 88°F temperature drop through 5-foot of rock). See figure 25.

CONCLUSION

The objectives of the research, testing the instrumentation and gaining

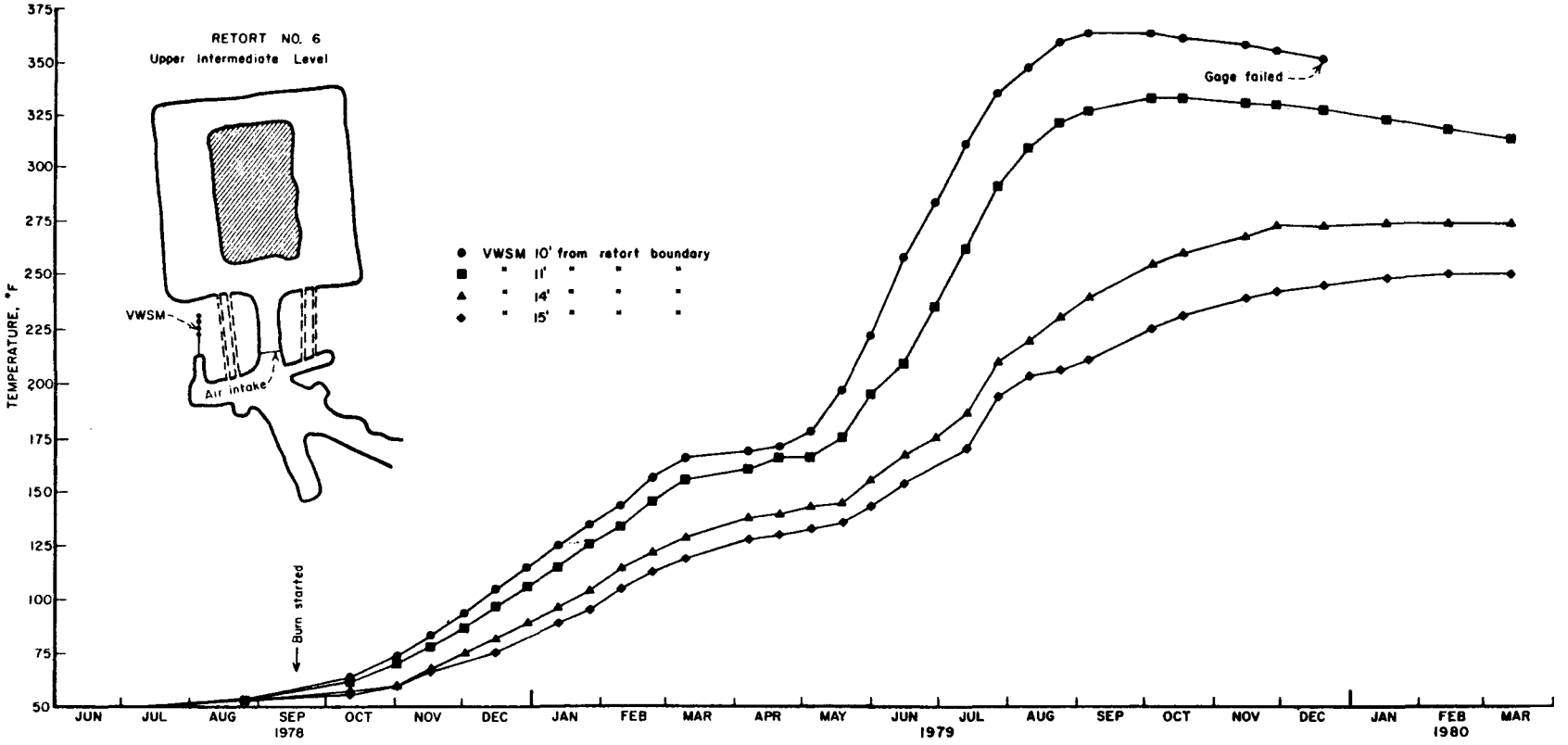


Figure 25 - Temperature Changes From In Situ Retort Burning.

an understanding of instrumentation placement, were achieved. The magnitudes and direction of the stresses, as determined from the limited data collected, were in agreement with the calculated stress changes due to the temperature changes. Monitoring surface elevation changes should be considered for future in situ retorting for the following reasons. First, for if subidence is detected, it will define the limits of the size of the retort in relationship to the overburden height. Second, when heating an area of ground (the size of this area is undefined at this period in time), the expansion under total confinement can cause the surface to rise.

It should be noted that this section of the report is incomplete since temperature data is still being collected and ambient temperature has not been reached. The information presented is for information purposes and additional or new conclusion may be obtained at the conclusion of the phase of study which is only estimated to last as much as one year or longer.

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1. Miller, R. J., F. D. Wang, T. Sladek, and C. Young. The Effect of In Situ Retorting on Oil Shale Pillars. Interim Report on U.S.B.M. Contract HO262031, 1979.

2. Duvall, W. I. Interpertation of Data Obtained with the Vibrating Wire Stressmeter. Paper researched for the Bureau of Mines, 1978.

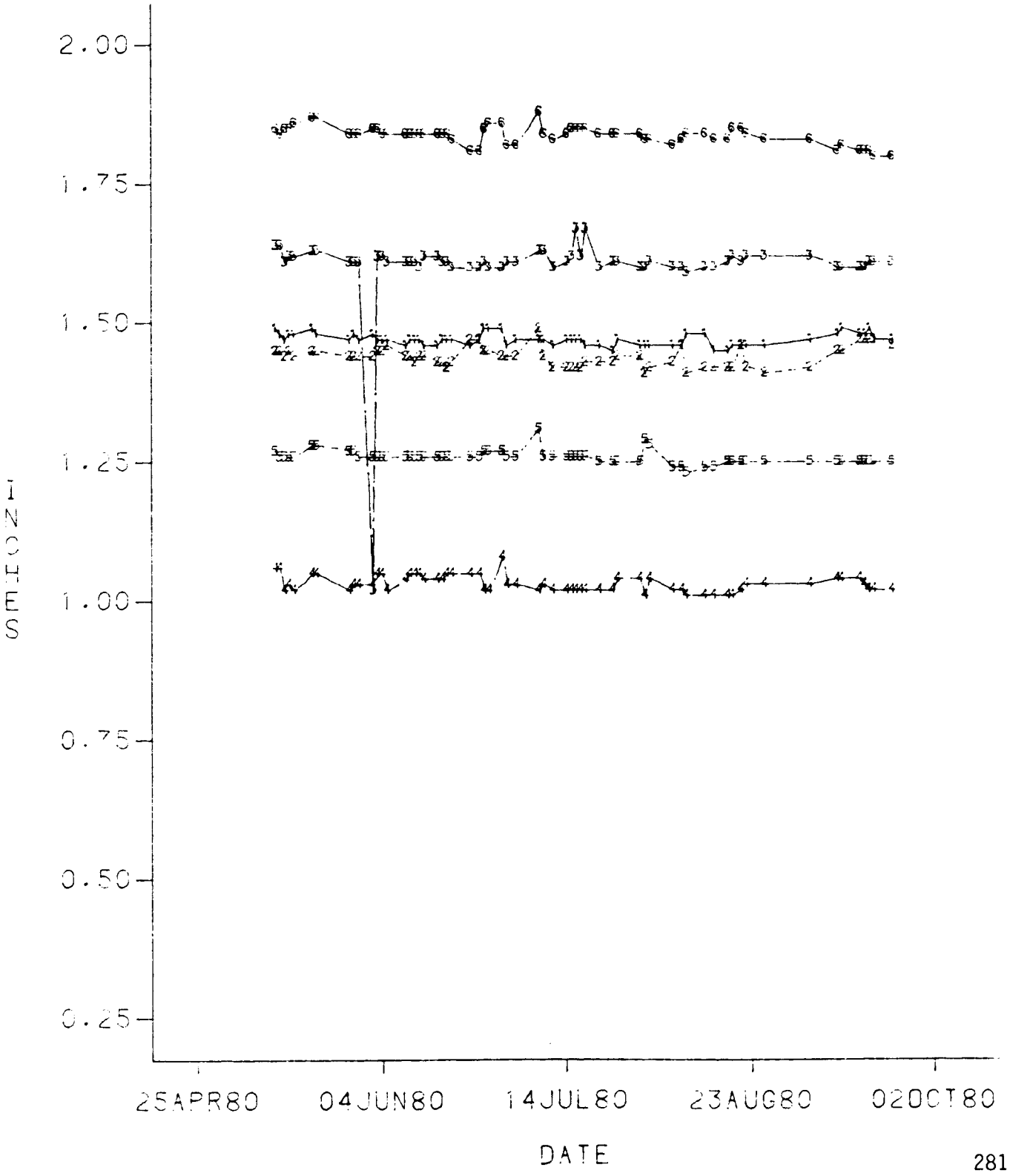
APPENDIX C

Retort 7 and 8 Mine Stability Data

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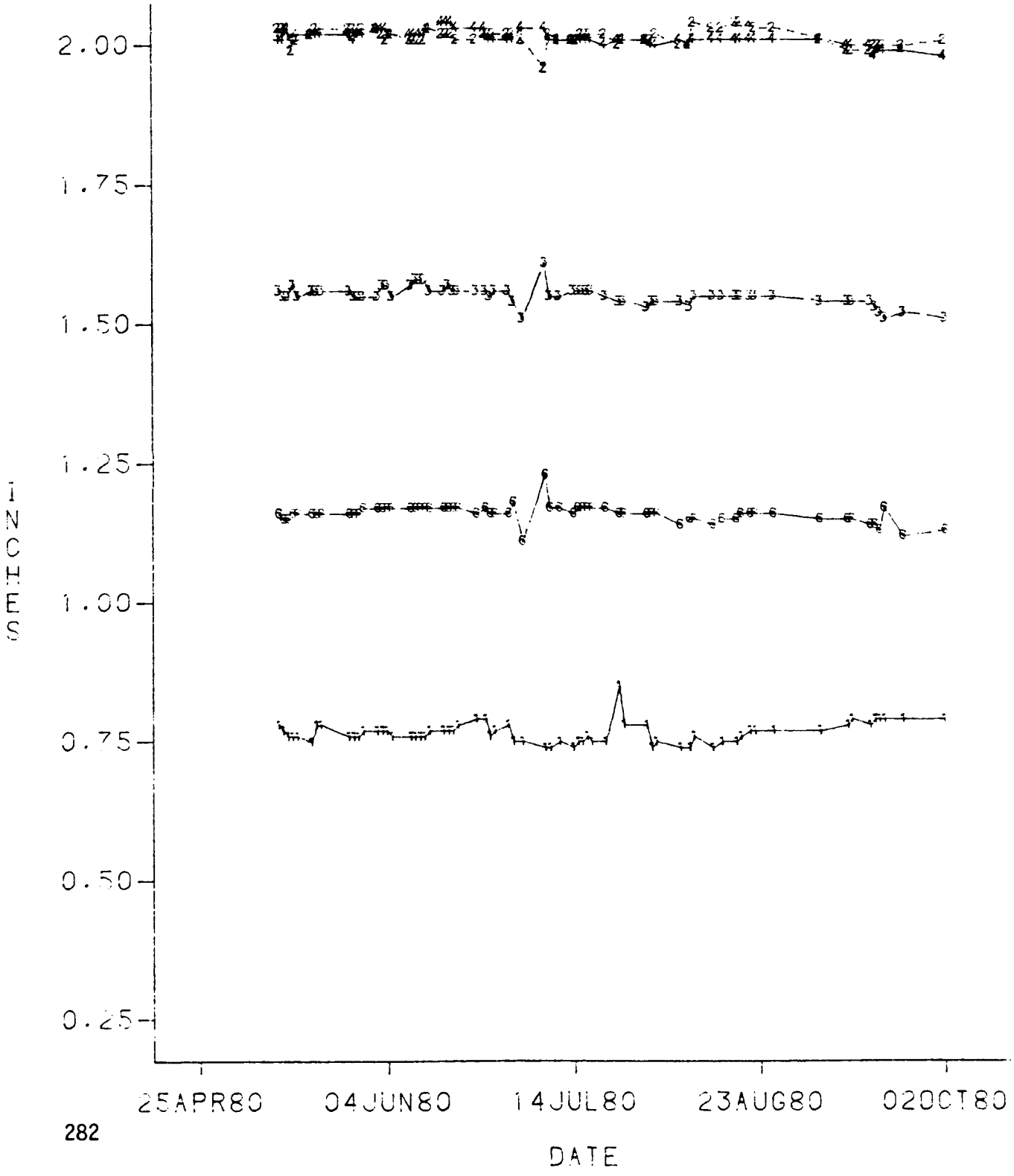
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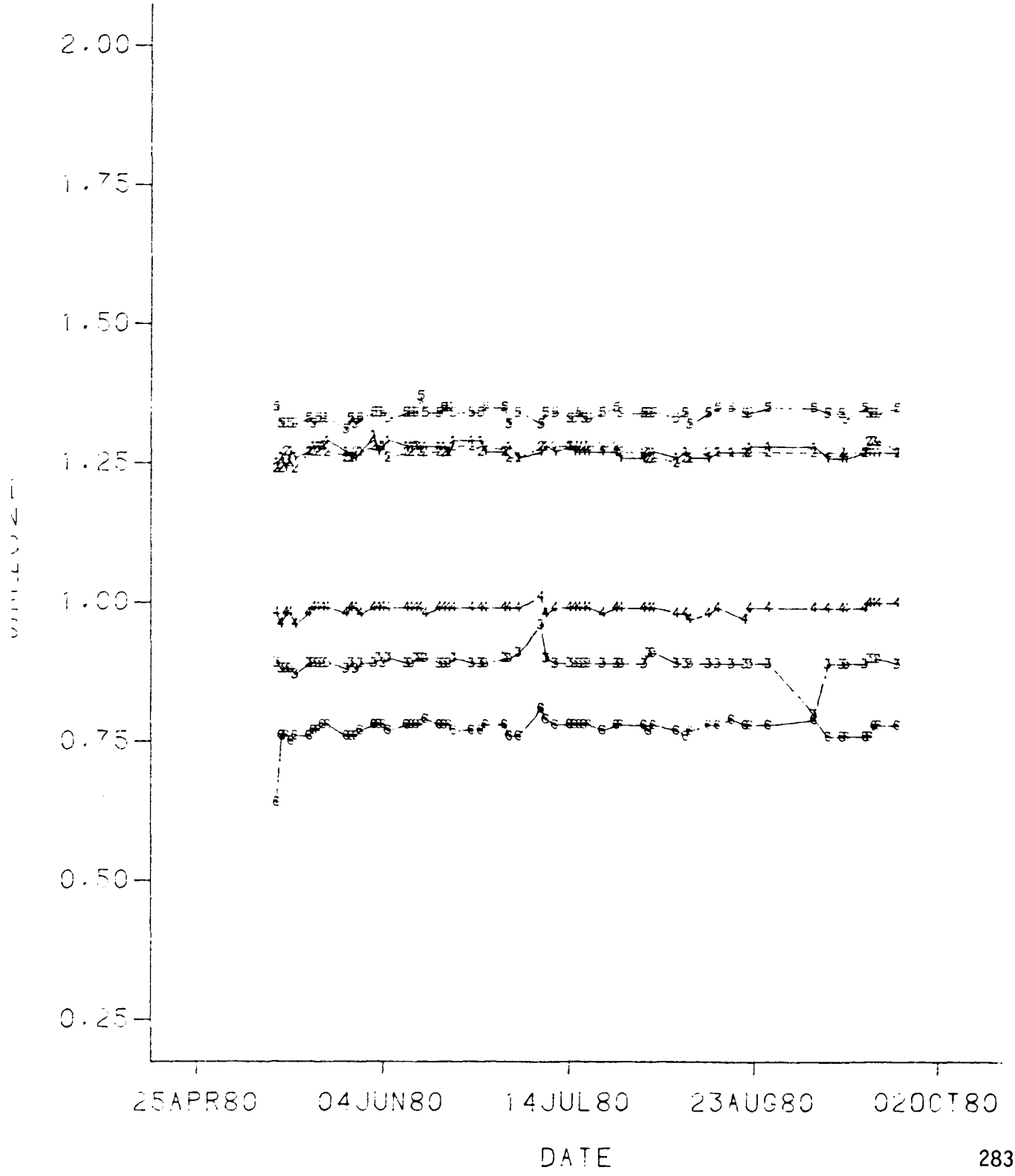
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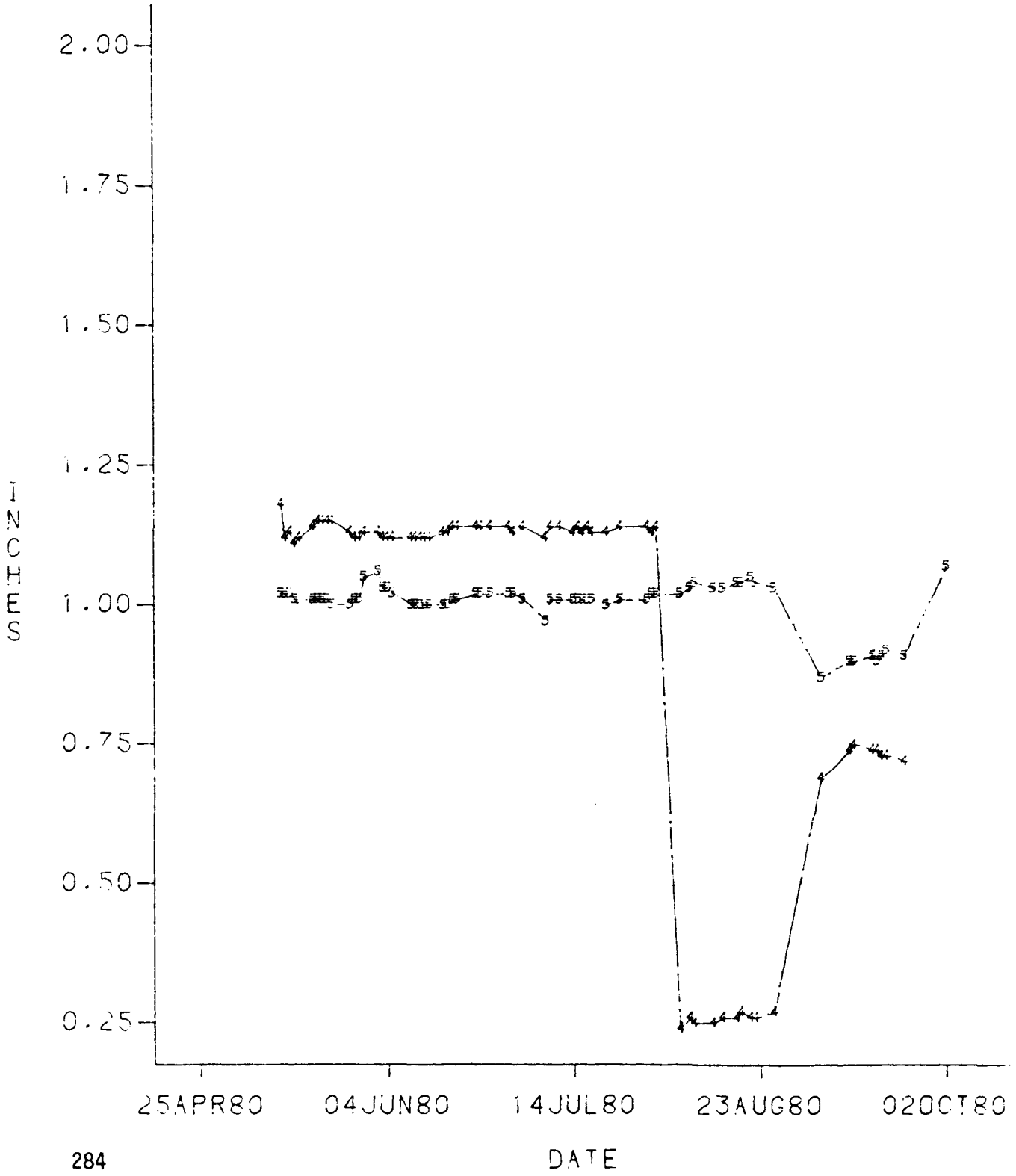
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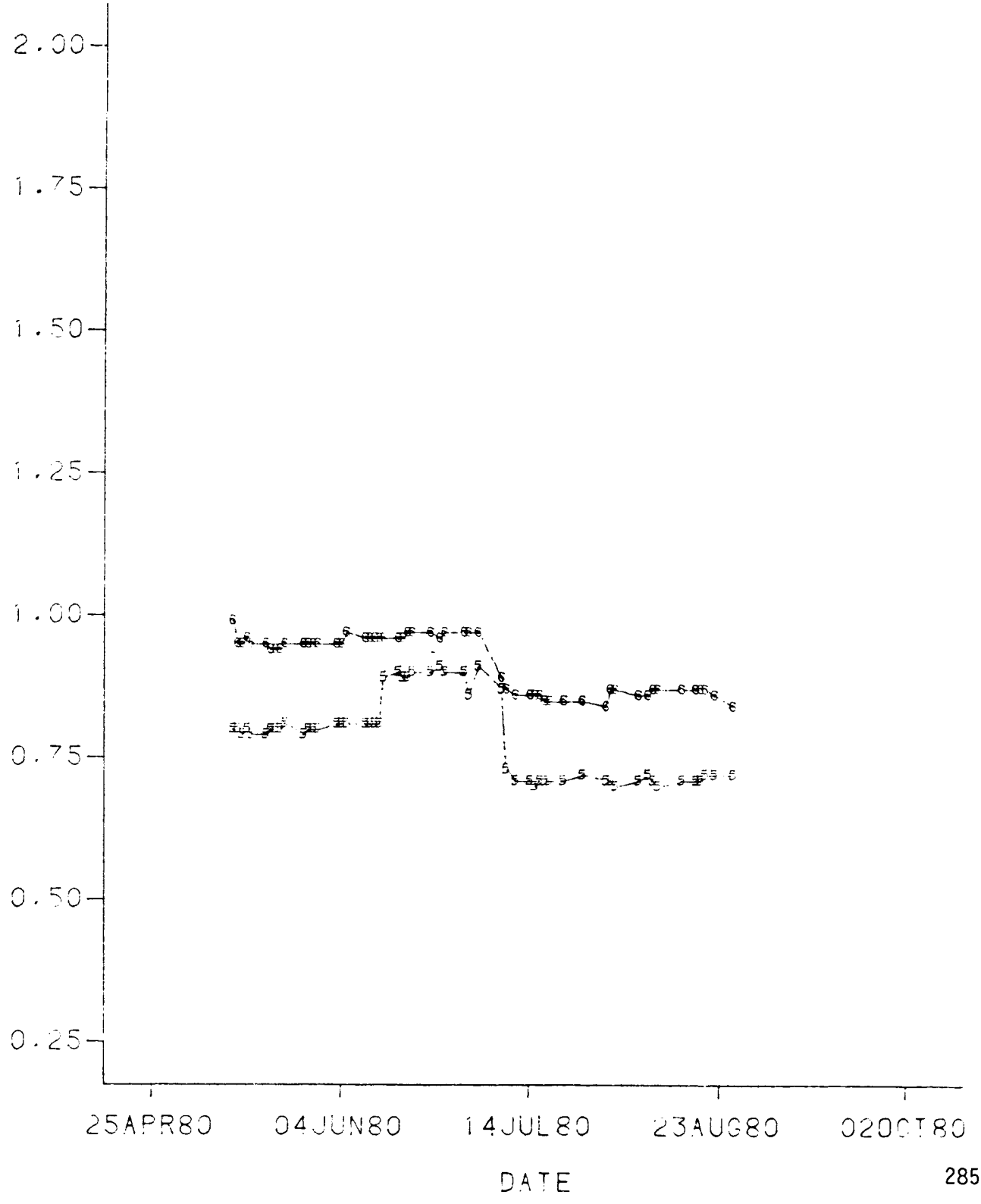
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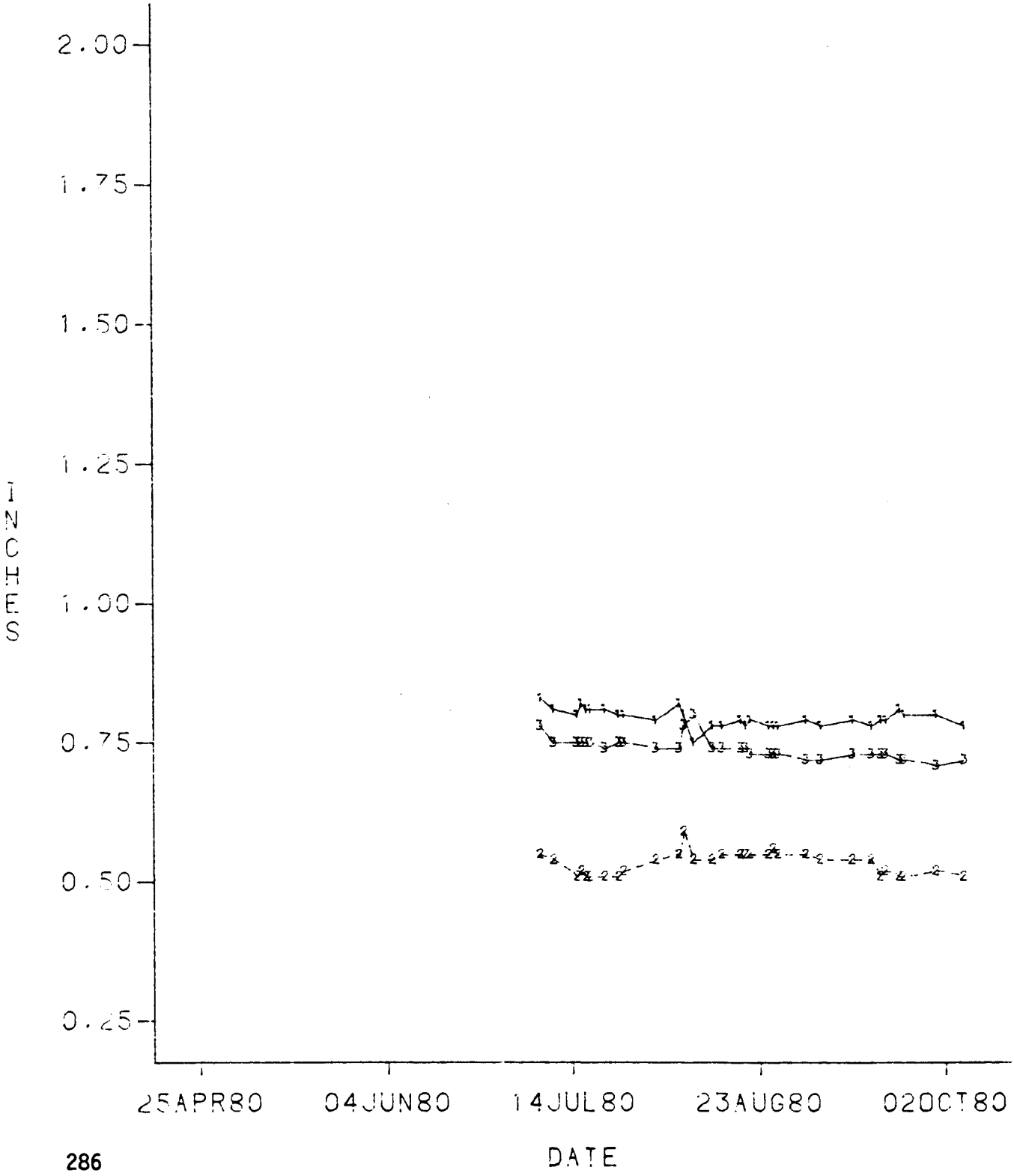
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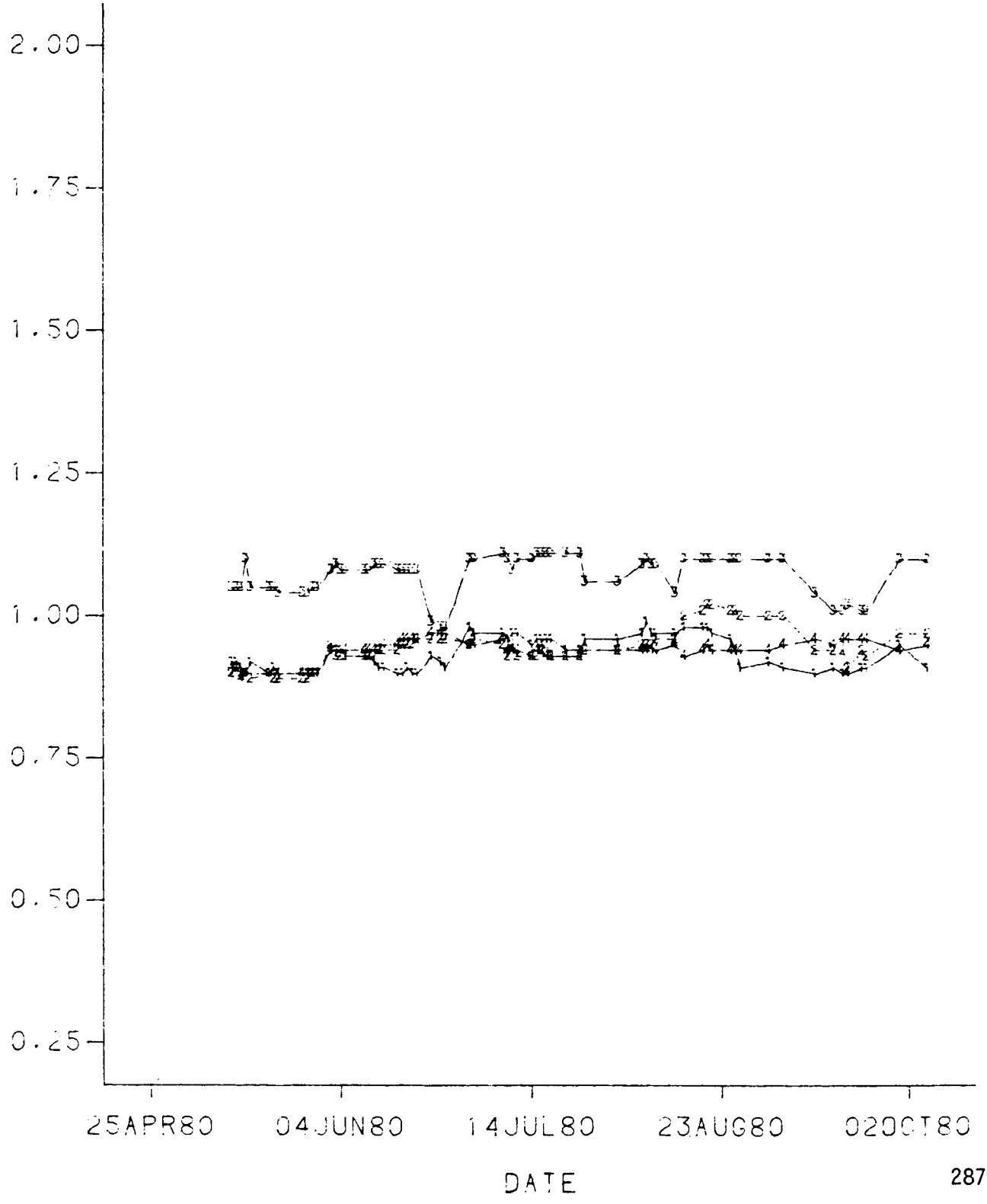
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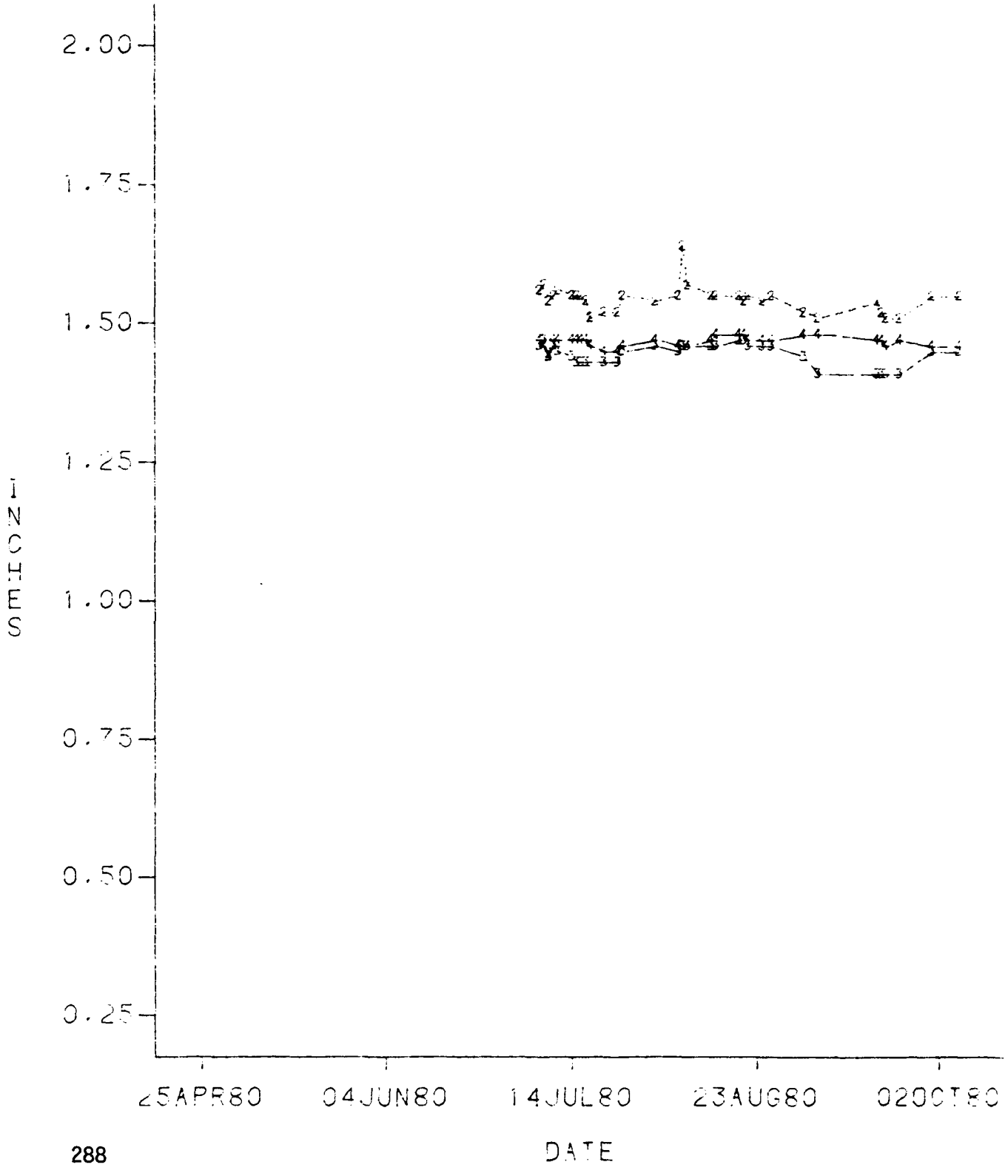
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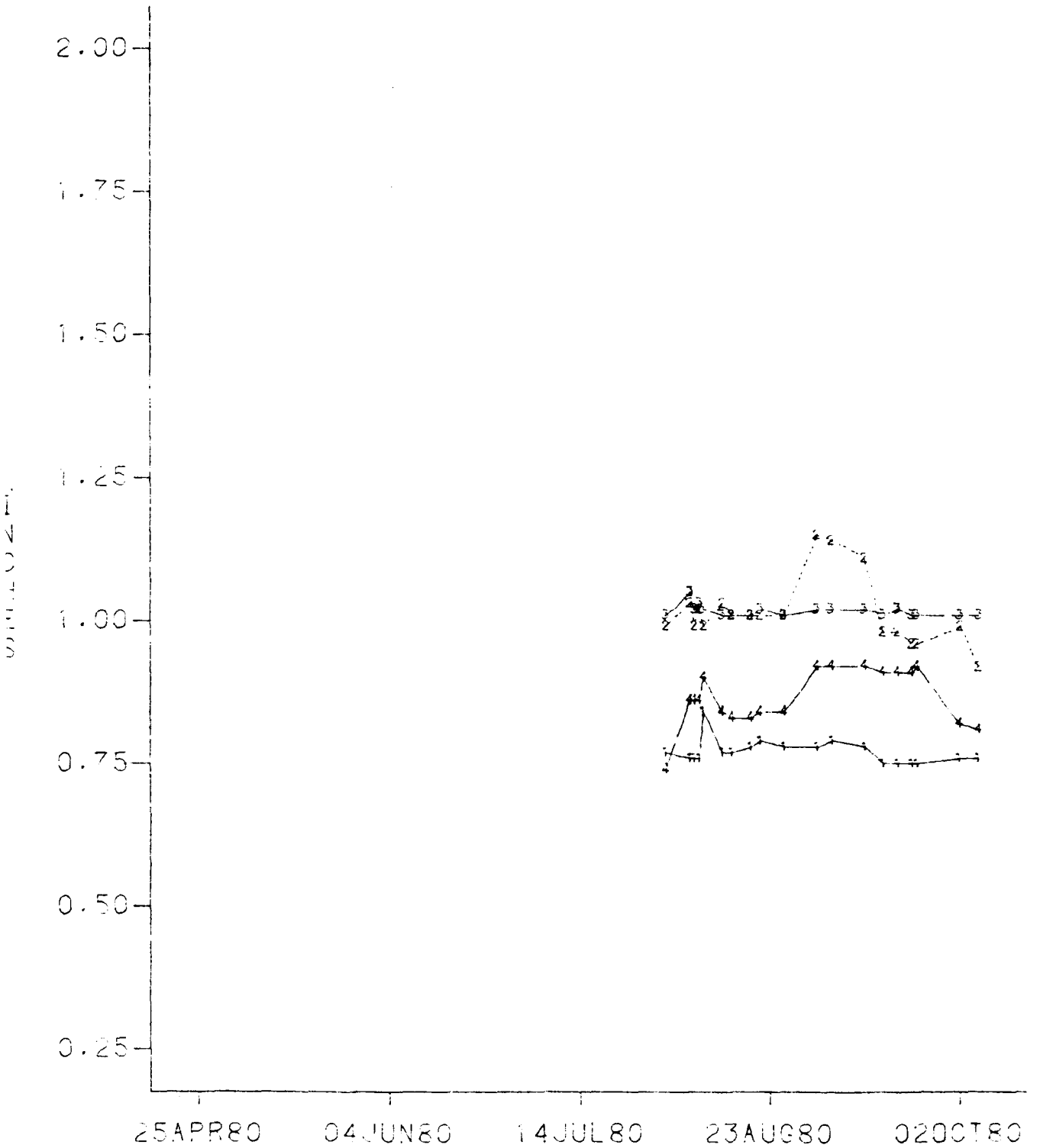
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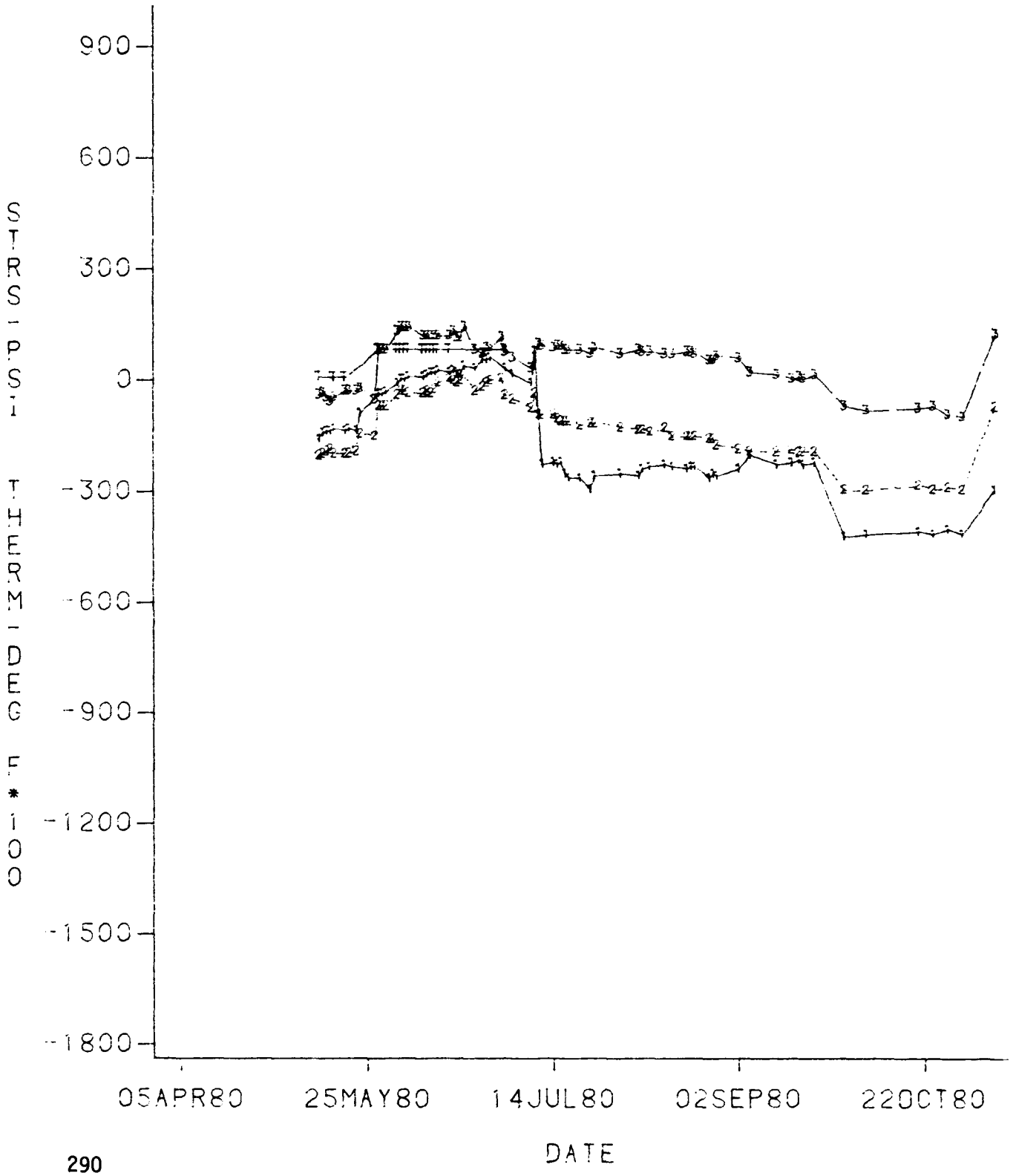
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STRESS AND THERMOCOUPLE READINGS

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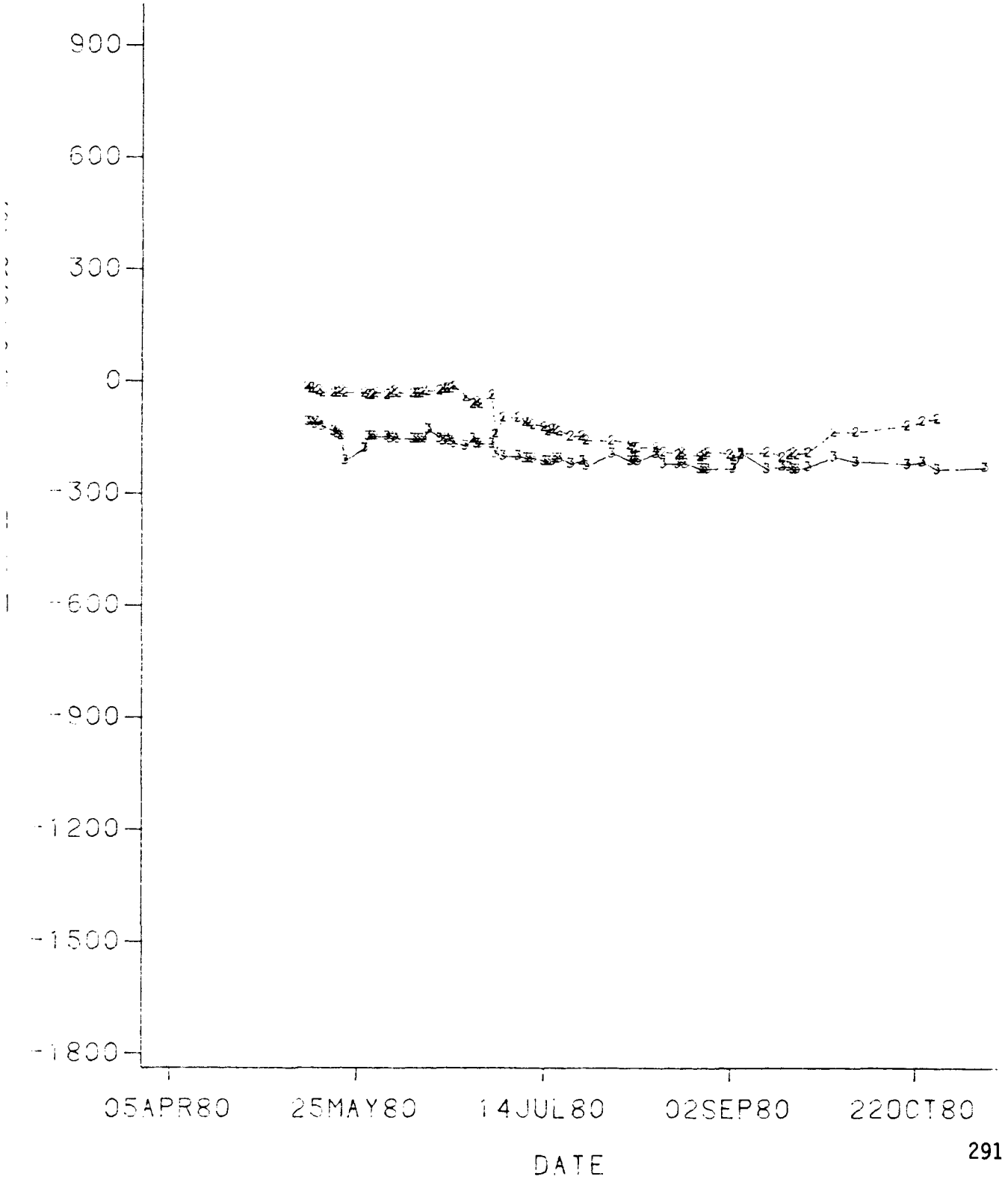
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STRESS AND THERMOCOUPLE READINGS

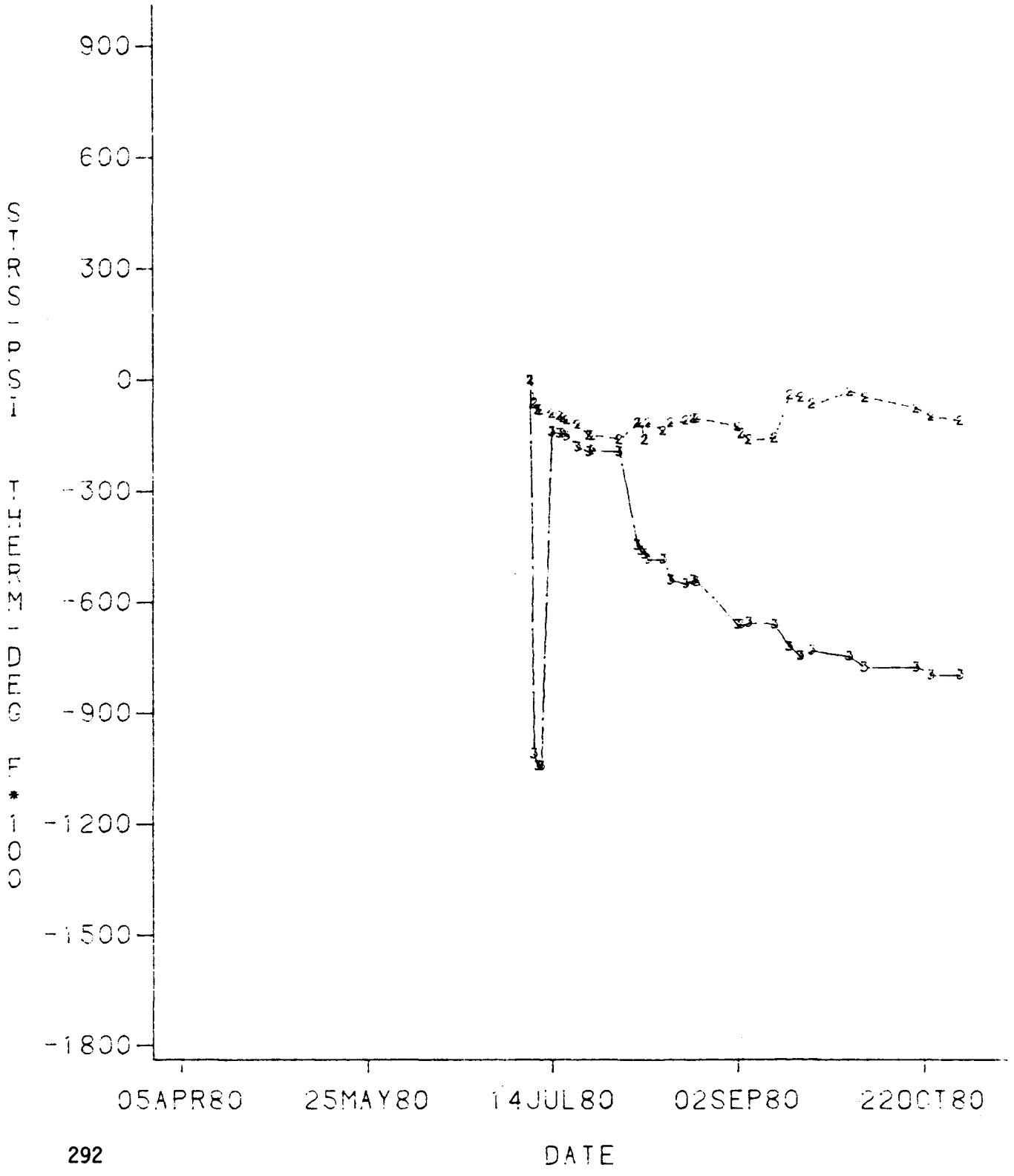
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HOLE= RM5



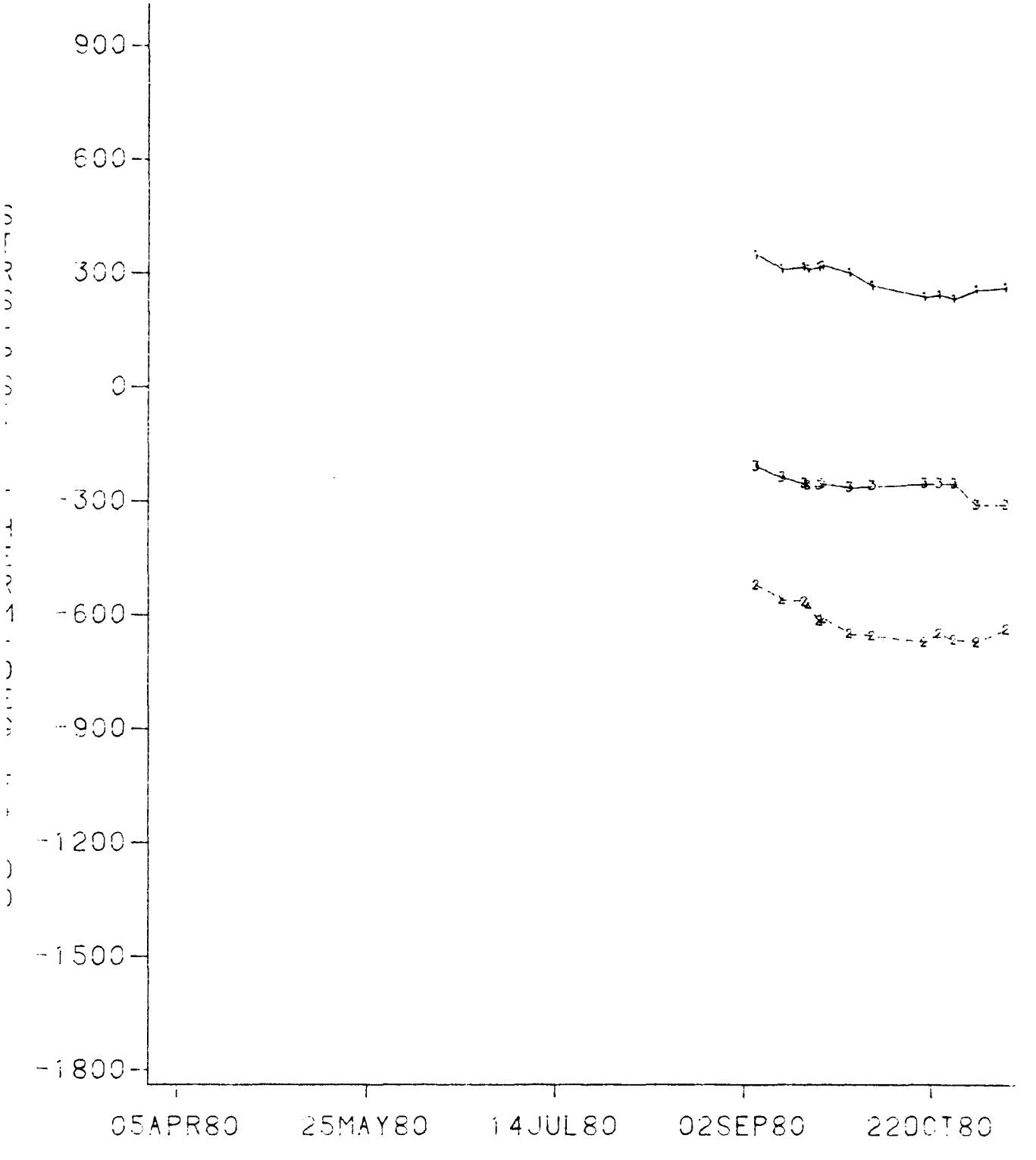
STRESS AND THERMOCOUPLE READINGS

NUMBERS INDICATE ANCHOR # T=THERM IF AVAIL
HOLE=RM8



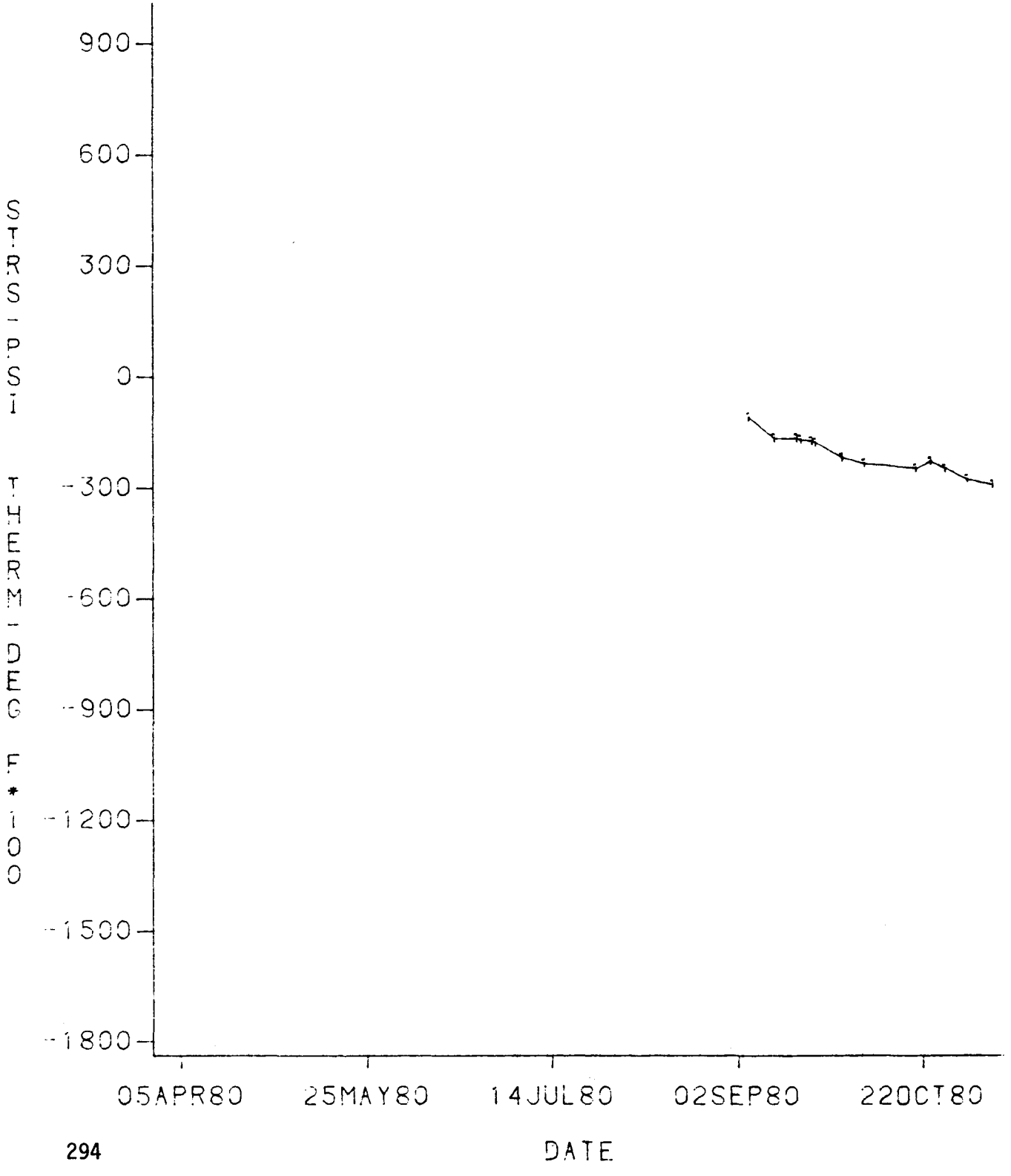
STRESS AND THERMOCOUPLE READINGS

NUMBERS INDICATE ANCHOR # T=THERM IF AVAIL
HOLE=RM15



STRESS AND THERMOCOUPLE READING

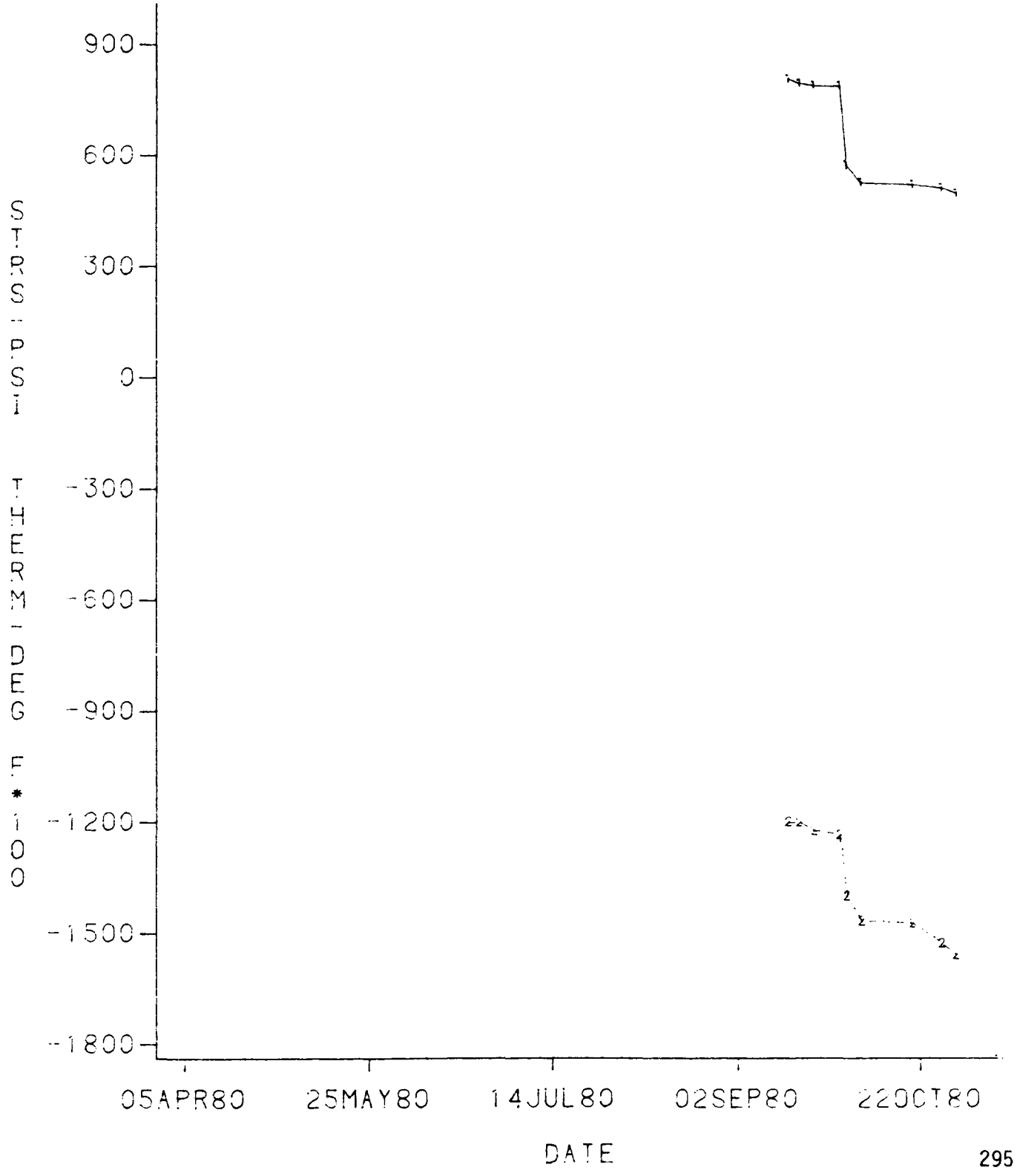
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HOLE=RM16



STRESS AND THERMOCOUPLE READINGS

NUMBERS INDICATE ANCHOR # T=THERM IF AVAIL

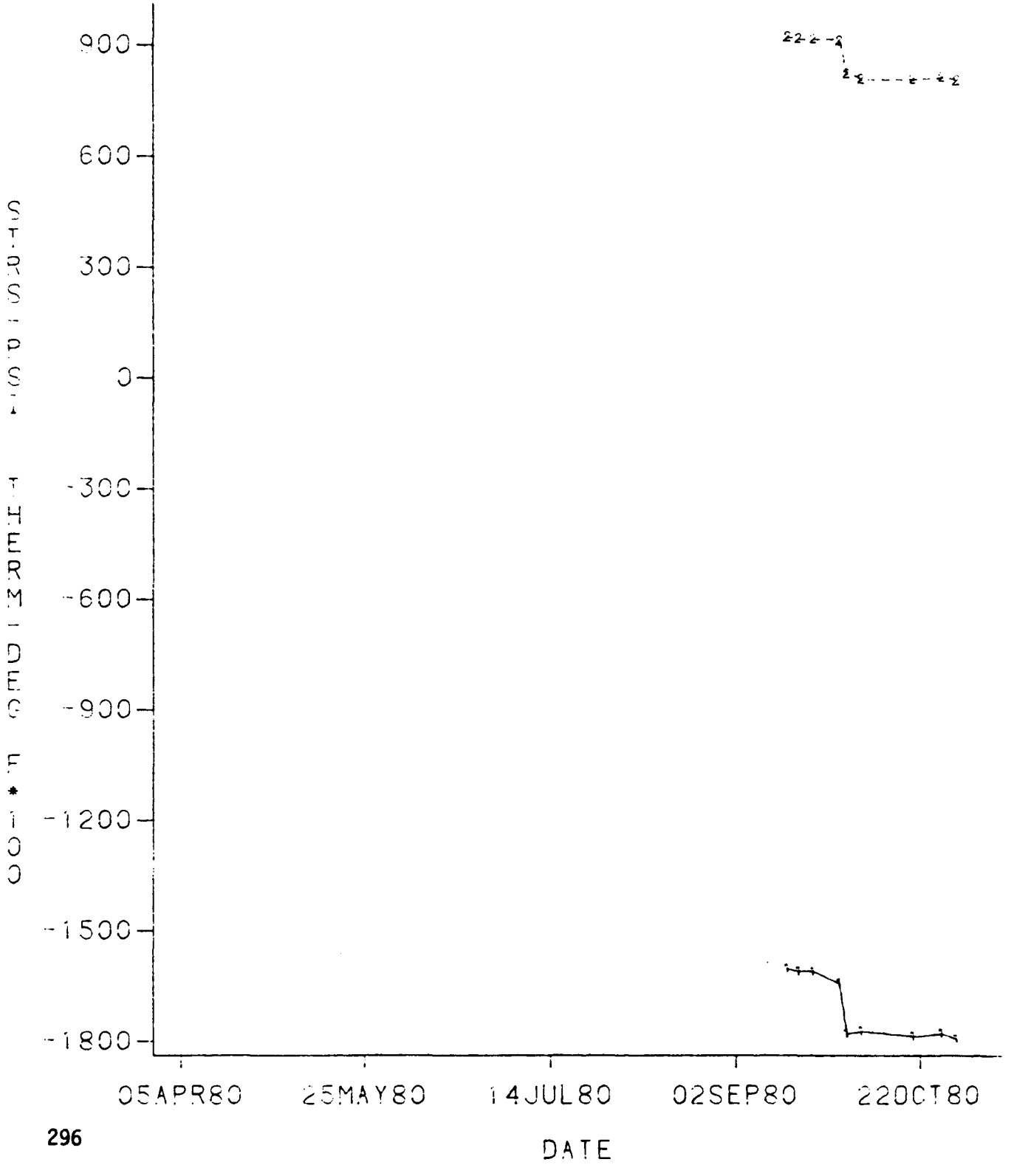
HOLE= RM17



STRESS AND THERMOCOUPLE READINGS

NUMBERS INDICATE ANCHOR # T=THERM IF AVAIL.

HOLE= RM18



APPENDIX D

Logan Wash Water Monitoring Program

SUBSURFACE DISPOSAL PERMIT FOR RETORTS 7 and 8

Split Sample Storage Requirements

Frequency	Sites	Bottles per Site
Weekly	7	4 - 1000 ml
Monthly	9	4 - 1000 ml
Semi-annually	9	7 - 1000 ml

When a monthly sample is taken, no additional weekly sample is taken. When a semi-annual sample is taken, no additional monthly or weekly samples are taken.

SUBSURFACE DISPOSAL PERMIT FOR RETORTS 7 and 8

Quarterly Reporting Schedule

Sites	Weekly Data	Monthly Data	Semi-annual Data
UL-109 UL-110 PL-111 PL-112 LMB-1 LW-108 LW-101A	Conductivity Visible Oil and Grease pH Temperature Water Level Li SCN NH_3-N Phenols	As, B, Ca, Mg, Mo, K, Na, Se, tAlk, HCO_3, CO_3, Cl, F, NO_3, SO_4, S_2O_3, TDS, Kjel-N, DOC	Al, Ba, Be, Br, Cd, Cr, Cu, Ga, Ge, Fe, Pb, Mn, Hg, Ni, Ag, Zn, natural U, SiO_2, total sPO_4, COD, oil and grease, NO_3+NO_2, pyridine, gross alpha, gross beta, Rn^{226} (if performed), S, CN

Sites	Monthly Data	Semi-annual Data
LW-106 LW-112 Logan Wash Dry Gulch Upper Roan Creek Lower Roan Creek Smith Gulch	Conductivity Visible Oil and Grease pH Temperature Water Level or Flow Rate As, B, Ca, Li, Mg, Mo, K, Na, Se, V, tAlk, HCO_3, CO_3, Cl, F, NO_3, SO_4, S_2O_3, TDS, SCN, Kjel-N, NH_3-N, DOC, phenols	Al, Ba, Be, Br, Cd, Cr, Cu, Ga, Ge, Fe, Pb, Mn, Hg, Ni, Ag, Zn, natural U, SiO_2, total sPO_4, COD, oil and grease, NO_3+NO_2, pyridine, gross alpha, gross beta, Rn^{226} (if performed), S, CN

Sites	Semi-annual Data
LW-115 LW-22 LW-102 LW-121	Conductivity Visible Oil and Grease pH Temperature Water Levels As, B, Ca, Li, Mg, Mo, K, Na, Se, V, tAlk, HCO_3, CO_3, Cl, F, NO_3, SO_4, S_2O_3, TDS, SCN, Kjel-N, NH_3-N, DOC, phenols

Sites	Quarterly Data
Retort 1	Conductivity
Retort 2	Visible Oil and Grease
Retort 3	pH
Retort 4	Temperature
Retort 5	Li
Retort 6	SCN
UIL-SW1	NH_3-N
UIL-SE2	Phenols
LIL-SW1	
LIL-SE2	
LIL-N3	
PLRL-1	

Sites	Data	Frequency
Retort 7 Sump Retort 8 Sump	Conductivity Visible Oil and Grease pH Temperature Li SCN NH_3-N (Bottle Schedule 1) Phenols	Prior to ignition - every 2 weeks (last 3 samples only) During Retorting - weekly First 2 months after shut down - monthly

For reporting, monthly parameters are in addition to weekly parameters; semi-annual parameters are in addition to monthly and weekly parameters.

CODE	
01	C.B. Seepage Wells Monthly
02	
03	
04	
05	
06	
07	LW NPDES Special Sample, In-house
08	LW NPDES, Weekly
09	C.B. No Name Station
10	C.B. NPDES, Weekly
11	C.B. NPDES, Monthly
12	C.B. NPDES, Semi-annually
13	
14	
15	
16	
17	
18	
19	
20	DMP Surface Water Monthly
21	DMP Surface Water Quarterly
22	DMP Surface Water Semi-annually
23	DMP Surface Water Annually
24	DMP Springs and Seeps Quarterly
25	DMP Springs and Seeps Semi-annually
26	DMP Springs and Seeps Annually
27	DMP Alluvial Wells Quarterly

WATER ANALYSIS PARAMETER CODES (Cont.)

Code	
28	DMP Alluvial Wells Semi-annually
29	DMP Alluvial Wells Annually
30	DMP Deep Wells Semi-annually
31	DMP Deep Wells Annually
32	
33	
34	
35	
36	
37	
38	
39	
40-40S	LW Ambient Monitoring Weekly, Subsurface Disposal Permit
41-41S	LW Ambient Monitoring Monthly, Semi-annually, Subsurface Disposal Permit
42-42S	LW Ambient Monitoring Semi-annually, Subsurface Disposal Permit
43	
44	
45	
46	LW Process Water Monitoring, Subsurface Disposal Permit
47	LW Process Water Monitoring, In-house
48	LW Spent Retorts Monitoring, Quarterly, Subsurface Disposal Permit and In-house
49	
50	C.B. VE Shaft

SUBSURFACE DISPOSAL PERMIT RETORTS 7 & 8

Weekly Ambient Monitoring

The following locations, UL-109, UL-110, PL-111, PL-112, LMB-1, LW-108, LW-101A, will be collected in a 2½ gallon carboy plastic container. The sample will then be split and preserved in two identical sets of bottles. One set, code 40, is analyzed immediately while the other, code 40S, will be stored until the results of the first set are examined. If none of the results are questionable both sets will be dumped. If the analysis shows out of line value the second set will be run as a check.

The water samples to be analyzed are listed under code 40, while the shelved suite will be code 40S, and both will comprise the following bottles 3-4-6-7.

These are the parameters to be analyzed:

Bottle 3: Dissolved metals: Li

Bottle 4: SCN

Bottle 6: NH_3-N

Bottle 7: Phenols

Field data will include: Conductivity, Visible Oil and Grease, pH, Temperature, and Water Level.

Monthly Ambient Monitoring

The following locations, UL-109, UL-110, PL-111, PL-112, LMB-1, LW-108, LW-106, LW-101A, LW-112, will be split and preserved, as described under Weekly Monitoring. The following locations will be sampled monthly but not split: Logan Wash, Dry Gulch, Upper and Lower Roan Creek, Smith Gulch, L2-PS-1, and L2-PS-2.

The water samples to be analyzed immediately are listed under code 41, while the stored suite will be coded 41S, and both will comprise the following bottles 3-4-6-7. These are the parameters to be analyzed:

Bottle 3: Dissolved metals: As, B, Ca, Li, Mg, Mo, K, Na, Se, V.
Bottle 4: tAlk, HCO_3, CO_3, Cl, F, NO_3, SO_4, S_2O_3, TDS, SCN.
Bottle 6: Kjel-N, NH_3-N.
Bottle 7: DOC, Phenols.

Field data will include: Conductivity, Visible Oil and Grease, pH, Temperature, and Water Levels or Flow Rate.

Semi-Annual Ambient Monitoring: Alluvial Wells

Alluvial wells LW-115, LW-22, LW-102, LW-121, will be sampled semi-annually. The sample code is 41, and will comprise the following bottles 3-4-6-7. These are the parameters to be analyzed:

Bottle 3: Dissolved metals: As, B, Ca, Li, Mg, Mo, K, Na, Se, V.
Bottle 4: tAlk, HCO_3, CO_3, Cl, F, NO_3, SO_4, S_2O_3, TDS, SCN.
Bottle 6: Kjel-N, NH_3-N.
Bottle 7: DOC, Phenols.

Field data will include: Conductivity, Visible Oil and Grease, pH, Temperature, and Water Levels.

Semi-Annual Ambient Monitoring

The following locations, UL-109, UL-110, PL-111, PL-112, LMB-1, LW-108, LW-106, LW-101A, LW-112, will be split and preserved as described under Weekly Monitoring.

There are additional locations for semi-annual sampling. They are LW-32, LW-33, LW-46, LW-47A, Logan Wash, Smith Gulch, Dry Gulch, Upper and Lower Roan Creek, and Bowdish Wash. These locations will not be split.

The water samples to be analyzed are listed under code 42, while the stored suite will be coded 42S, and will comprise the following bottles 3-4-6-7-9-1(These are the parameters to be analyzed:

Bottle 3: Dissolved metals: Al, As, Ba, Be, B, Br, Cd, Ca, Cr, Cu, Ga, Ge, Fe, Pb, Li, Mg, Mn, Hg, Mo, Ni, K, Se, Ag, Na, V_2O_5, Zn, natural U.

Bottle 4: tAlk, HCO_3, CO_3, Cl, F, NO_3, SiO_2, TDS, SO_4, SCN, S_2O_3, total sPO_4.

Bottle 6: Kjel-N, COD, NH_3-N, O and G.

Bottle 7: DOC, Phenols, NO_3 + NO_2, pyridine.

Bottle 8: Gross Alpha, Gross Beta.

Bottle 9: S

Bottle 10: CN

Field data will include: Conductivity, Visible Oil and Grease, pH, Temperature, and Water Levels or Flow Rate.

N.P.D.E.S. Monitoring

The flume in Dry Gulch and the Research Mine discharge point will be sampled weekly whenever there is a flow from either location. Two codes are assigned to this location, the first code 08 is for routine monitoring in compliance with the NPDES permit. The other code 07 will be used in the event that further characterization of the discharge is desired. Each code has a different set of parameters. When code 08 is specified no in-house *( ) parameters are analyzed. When code 07 is indicated, all the parameters listed below should be analyzed.

Code 08 will comprise bottles 2-4-5-6-7-9, while code 07 will comprise bottles 2-3-4-5-6-7-9. These are the parameters to be analyzed for both codes. The IN-HOUSE parameters, code 08, will be identified by *( ).

Bottle 2: Total Metals: As, B, Cr, Cu, Fe, Mo, Zn.
Bottle 3: Dissolved metals: *(B, Ca, K, Mg, Na).
Bottle 4: *(HCO_3), *(CO_3), F, *(NO_3), *(SCN), TDS, TSS.
Bottle 5: BOD_5.
Bottle 6: COD, *(Kjel-N), NH_3-N, O&G.
Bottle 7: *(DOC), Phenols.
Bottle 9: tS.
Special Bottle: *(Fec. Coliform).

Field data will include: Conductivity, Visible Oil and Grease, pH, Temperature, and Flow Rates.

PROCESS WATER MONITORING
Retort 7 and 8 Monitoring Schedule

Prior to retorting, water will be collected from the two sumps of Retort 7 and 8. This sampling will commence as soon as possible after rubblization of both retorts. This sampling will be performed every two weeks until ignit is started. From the beginning of ignition, throughout retorting, and until shut down of both retorts, sampling will be weekly. After shut-down, samplir is done every two weeks for two months, then monthly for three months. The sampling then reverts to a quarterly schedule.

Retort water monitoring is performed for two purposes: first, to compl with the Subsurface Disposal Permit and second, to obtain information of technical value to OXY. Both parameter sets are described on the next page. To avoid redundant effort, both sampling programs have been designed to coin as much as possible and it is intended that all samples will be taken at the same time. Five months after shut down, when the sampling schedule reverts t quarterly sampling, many of the in-house parameters can be eliminated. At t time Environmental Services will prepare an amended parameter list.

PROCESS WATER MONITORING
Retort 7 and 8 Parameters List

All Retort 7 and 8 water samples will be analyzed for two sets of parameters; one set in compliance with the Subsurface Disposal Permit and the other for in-house technical data. The set taken in compliance with the permit will be taken in accord with Bottle Schedule 1. This Schedule is derived from EPA approved methodology. However, it has been found that the EPA approved methodology is inappropriate for analysis of oil shale process waters. Therefore the second in-house parameters will be run on samples taken in accord with Bottle Schedule 2. This Schedule is developed based on the best information available on analysis of process waters. Each parameter set has a different code designation.

The compliance monitoring samples are designated as code 46, and comprise the following bottles 3-4-6-7. These are the parameters to be analyzed:

Bottle 3: Dissolved metals: Li
Bottle 4: SCN
Bottle 6: NH_3-N
Bottle 7: Phenols

These parameters will be reported to the State.

The in-house samples are designated as code 47, and comprise the following bottles 1-2-3-4-5-6 of Bottle Schedule 2. These are the parameters to be analyzed:

Bottle 1: TDS, TSS, tS, tAlk, HCO_3, CO_3, F, SiO_2.
Bottle 2: Cl, SO_4, NO_3, SCN, SO_3, S_2O_3, S_4O_6.
Bottle 3: $tS^=$, H_2S.
Bottle 4: Dissolved metals: Hg, Al, As, B, Ba, Ca, Cd, Cr, Cu, Fe, Li, Pb, Mg, Mo, Mn, Ni, K, Se, Sr, Ag, Na, V, Zn, DOC, EP toxicity metals.
Bottle 5: Kjeldahl nitrogen, NH_3-N.
Bottle 6: Phenols.
Bottle 9: Pyridines.

Field data will include: Conductivity, Visible Oil and Grease, pH, and Temperature. All field data will be reported to the State.

Quarterly Monitoring:

Spent Retorts 1, 2, 3, 4, 5, and 6 and Retort 6 Satellite Wells

Retorts 1, 2, 3, 4, 5, and 6 and UL-SW1, UL-SE2, LIL-SW1, LIL-SE2, LIL-N3, and PLRL-1 are to be sampled on a continuous quarterly sampling program under terms of the Subsurface Disposal Permit and to obtain information for OXY's use. These samples are listed under code 48 and comprise the following bottles 3-4-6-7.

These are the parameters to be analyzed:

Bottle 3: Dissolved metals: (Li), As, B, Ca, Mg, K, Na.

Bottle 4: (SCN), tAlk, HCO_3, CO_3, Cl, F, NO_3, TDS.

Bottle 6: (NH_3-N), Kjeldahl-N.

Bottle 7: (Phenols), DOC.

Only those parameters in ( ) and the field data will be reported to the State.

Field data will include: Conductivity, Visible Oil and Grease, pH, and Temperature.

Code 05

Sampling Frequency:	Quarterly
Locations:	Sumps of Retorts 1, 2, 3, 4, 5, and 6; UL-SW1, UL-SE2, LIL-SW1, LIL-SE2, LIL-N3, and PLRL-1
Sample Bottles:	3-4-6-7
Parameters:	Li, As, B, Ca, Mg, K, Na, SCN, tAlk, HCO_3, CO_3, Cl, F, NO_3, TDS, NH_3-N, Kjel-N, phenols, DOC
Field Data:	Conductivity, visible oil and grease, pH, temperature

Code 07

Sampling Frequency:	As needed
Locations:	Dry Gulch Discharge Point, Research Mine Discharge Point
Sample Bottles:	2-3-4-5-6-7-9
Parameters:	tAs, tB, tCr, tCu, tFe, tMo, tZn, sB, sCA, sK, sMg, sNa, HCO_3, CO_3, F, NO_3, SCN, TDS, TSS, BOD_5, COD, Kjel-N, NH_3-N, O & G, DOC, phenols, tS, fecal coliform
Field Data:	Conductivity, visible oil and grease, pH, temperature, flow

Code 08

Sampling Frequency:	Weekly when flowing
Locations:	Dry Gulch Discharge Point, Research Mine Discharge Point
Sample Bottles:	2-4-5-6-7-9
Parameters:	tAs, tB, tCr, tCu, tFe, tMo, tZn, F, TDS, TSS, BOD_5, COD, NH_3-N, O & G, phenols, tS
Field Data:	Conductivity, visible oil and grease, pH, temperature, flow

Code 40 and 40S

Sampling Frequency:	Weekly
Locations:	UL-109. UL-110, PL-111, PL-112, LMB-1, LW-108, LW-101A
Sample Bottles:	3-4-6-7 (split samples)
Parameters:	Li, SCN, NH_3-N, phenols
Field Data:	Conductivity, visible oil and grease, pH, temperature, water level

Code 41 and 41S

Sampling Frequency:	Monthly
Locations:	UL-109, UL-110, PL-111, PL-112, LMB-1, LW-108, LW-101A, LW-106, Logan Wash, Dry Gulch, Smith Gulch, Upper and Lower Roan Creek, L2PS1, L2PS2
Sampling Frequency:	Semi-annually
Locations:	LW-115, LW-102, LW-22, LW-121
Sample Bottles:	3-4-6-7 (split samples for UL-109, UL-110, PL-111, PL-112, LMB-1, LW-108, LW-101A only)
Parameters:	As, B, Ca, K, Li, Mg, Mo, Na, Se, V, tAlk, HCO_3, CO_3, F, NO_3, SO_4, S_2O_3, SCN, TDS, Kjel-N, NH_3-N, DOC, phenols
Field Data:	Conductivity, visible oil and grease, pH, temperature, and water level or flow

Code 42 - 42S

Sampling Frequency: Semi-annually

Locations: UL-109, UL-110, PL-111, PL-112, LMB-1, LW-108, LW-106, LW-101A, LW-112, LW-32, LW-33, LW-46, LW-47A, Logan Wash, Dry Gulch, Smith Gulch, Upper and Lower Roan Creek, Bowdish Wash

Sample Bottles: 3-4-6-7-8-9-10 (split bottles 3-4-6-7 for UL-109, UL-110, PL-111, PL-112, LMB-1, LW-108, LW-101A only)

Parameters: Al, As, Ba, (Be), B, Br, Cd, Ca, Cr, Cu, Ga, Ge, Fe, Pb, Li, Mg, Mn, Hg, Mo, Ni, K, Se, Ag, Na, (Natural U), (V_2O_5), Zn, tAlk, HCO_3, CO_3, Cl, F, NO_3, SiO_2, TDS, SO_4, SCN, S_2O_3, NH_3-N, COD, O & G, Kjel-N, DOC, Phenols, (Gross Alpha), (Gross Beta), S, (CN), total sPO_4, NO_3+NO_2, (pyridine)

Those parameters in ( ) will be sent to C.D.M. for analysis.

Field Data: Conductivity, visible oil and grease, pH, temperature, and water level or flow.

Code 46

Sampling Frequency:

Prior to ignition	- every two weeks
During retorting	- weekly
First 2 months after shut-down	- every two weeks
3rd through 5th month after shut-down	- monthly

Locations: Retorts 7 & 8 Sumps

Sample Bottles: 3-4-6-7 Bottle Schedule 1

Parameters: Li, SCN, NH_3-N, phenols

Field Data: Conductivity, visible oil and grease, pH, temperature

Code 47

Sampling Frequency: Same as Code 46

Locations: Retorts 7 & 8 Sumps

Sample Bottles: 1-2-3-4-5-6 Bottle Schedule 2

Parameters: TDS, TSS, tS, tAlk, HCO_3, CO_3, F, SiO_2, Cl, SO_4, NO_3, SC
SO_3, S_2O_3, S_4O_6, $tS^=$, H_2S, Hg, Al, As, B, Ba, Ca, Cd, Cr
Cu, Fe, Li, Pb, Mg, Mo, Mn, Ni, K, Se, Sr, Ag, Na, V, Zn
DOC, Kjel-N, NH_3-N, phenols, pyridine

Field Data: Same as Code 46

Bottle Schedule 1

H. S. Skogen
Proposed Water Sampling Container and Preservation
January 16, 1980

BOTTLE #	VOL ml	CONTAINER[a]	PRESERVATIVE[b]	PARAMETERS
1.	1000	P	HNO_3 to pH <2 0.05% $K_2 Cr_2 O_7$	t Hg
2.	1000	P	HNO_3 to pH <2 unfiltered	total metals hardness
3.	1000	P	HNO_3 to pH <2 filter 0.45μ	dissolved metals s Al
4.	1000	P	unfiltered untreated, cool 4°C	Alkalinity, Cl, F, turbidity, SO_4, TDS, TSS, NO_3, SiO_2
5.	1000	P	unfiltered untreated, cool 4°C	orthophosphate Br BOD
6.	1000	G	H_2SO_4 to pH <2 Cool 4°C	NH_3-N, Oil & Grease, COD, Kjeldahl-N
7.	1000	G	H_2SO_4 to pH <2 Cool 4°C	Phenols NO_3 + NO_2, TOC, DOC
8.	1000	P	HNO_3 to pH <2	radioactivity (alpha, beta, radium, etc.)
9.	1000	P	Cool 4°C Zinc Acetate	Sulfide
10.	1000	P	Cool 4°C NaOH to pH >12	Cyanide
11.	1000	G	Filter Ag membrane	Fractionation of organic carbon
12.	250	G	Sterile (Special bottles avail.G.J.Lab)	Total coliform, Fecal coliform, Fecal Streptococci
13.	1000	G (Teflon-lined cap)	Cool 4°C untreated	MBAS PNA

ON SITE DETERMINATIONS: D.O., pH, temp., conductivity, flow, sulfite, color, visible oil and grease (sheen).

a. Polyethylene (P); Glass (G),
b. Sample preservation should be performed immediately upon sample collection, Soluble (s); total(t),
Samples should be filtered (0.45μ membrane) immediately on-site before adding preservative for dissolved metals.

Bottle Schedule 2

PROCESS WATER SAMPLING AND PRESERVATION

Bottle #	Required Volume (ml)	Container	Preservative	Parameters
I	1000	P	filter (a) N_2 purge Cool 4°C	TDS, TSS, tS, t, Alk, CO_3, HCO_3, F, SiO_2, mineral carbon, tN
II	250	P	filter (a) N_2 purge Cool 4°C	Br, Cl, NO_3, NO_2, SO_4, SCN, SO_3, S_2O_3, S_4O_6, PO_4
III	200	P	unfiltered Cool 4°C 1:1 50% SOAB	$tS^=$, H_2S
IV	500	P	filter (b) N_2 purge Cool 4°C	Hg, dissolved metals, DOC, NH_4, EP Toxicity metals
V	1000	P	filter (a) N_2 purge Cool 4°C	COD, Kjel-N, NH_3-N
VI	100	G (poly seal cap)	filter N_2 purge Cool 4°C	phenol, O & G
VII	1000	P	filter (a) N_2 purge Cool 4°C	Radiochemistry (gross α & β, U, Ra^{226}, Sr^{90}, Ce^{137}, etc.)
VIII	250	P (poly seal cap)	filter Ag membrane N_2 purge Cool 4°C	DOC Fractionation
IX	500	G (teflon lined cap)	unfiltered N_2 purge Cool 4°C	Special organics
X	1000	P	unfiltered N_2 purge Cool 4°C NaOH to pH>12	CN

On-site determinations: dissolved oxygen, pH, temperature, conductivity, flow, color, visible oil and grease (sheen).

Notes: P - convention polyethylene
G - glass

Process Waters

Filtration

(a) Cool the water to 40°C and filter through glass wool or phase separation paper using gravity filtration to remove insoluble organics and large particulates. This procedure removes floating oil.

(b) Cool water to 4°C and filter through 0.45 μm membrane filter using N_2-gas pressure filter.

N_2 Purge

Bubble sample with low flow N_2 to remove any oxidizing gases.

APPENDIX E

Hydrology and Water Quality Data

LOGAN WASH LEVELS DATA

WATER LEVELS DATA

Station	Date	Level (ft)
LWD607	8/13/80	35.0
	12/23/80	35.0
	2/12/81	37.0
	3/11/81	35.2
	4/16/81	26.9
LWD608	Mine Water Sump	No Water Levels
LWD610	12/17/80	45.0
	2/12/81	39.0
	3/11/81	45.4
LWD611	12/17/80	55.0
	2/12/81	39.0
	3/11/81	53.0
LWD032	9/16/80	555.0
	12/04/80	540.0
LWD046	9/16/80	621.0
	12/04/80	625.0
LWD602	8/13/80	140.0
	11/13/80	147.0
	2/12/81	101.0
	3/11/81	150.2
LWD603	8/13/80	15.0
	3/11/81	25.4
LWD604	8/13/80	15.0
	10/30/80	24.0
	11/13/80	16.0
	12/17/80	20.0
	1/14/81	21.0
	2/12/81	21.0
	3/11/81	30.3
LWD605	8/13/80	18.0
	12/17/80	24.0
	1/14/81	33.0
	2/12/81	19.0
	3/11/81	25.4
LWD606	8/13/80	35.0
	12/23/80	40.0
	1/04/81	40.0
	2/12/81	32.0
	3/11/81	35.2
	4/16/81	26.9
LWA102	8/22/78	32.0
	5/08/80	43.0
	8/06/80	42.0
	9/04/80	43.0
	11/06/80	45.0
	12/04/80	46.0
LWA103	1/29/81	88.0
	5/18/81	56.0
LWA104	8/22/78	31.5
	7/23/80	35.0
	1/29/81	35.0
	5/18/81	35.0
LWA112	6/19/80	64.8
	7/24/80	66.5
	8/20/80	65.0
	10/27/80	75.0
	11/19/80	54.0
	12/16/80	36.0
	3/17/81	64.8
	4/30/81	71.0
	5/06/81	68.0
	5/13/81	73.6
LWA022	6/19/80	7.0
	10/27/80	8.0
	11/19/80	12.0
	12/16/80	18.0
	1/20/81	22.0
	2/18/81	36.0
	3/17/81	29.0
	5/28/81	26.0

WATER LEVELS DATA (Continued)

Station	Date	Level (ft)
LWA101	3/13/80	61.0
	4/21/80	55.0
	6/19/80	55.0
	7/24/80	67.0
	8/20/80	75.0
	10/27/80	86.0
LWA100	12/16/80	52.0
	2/18/81	75.8
	3/17/81	64.8
	4/02/81	63.2
	4/09/81	65.3
	4/16/81	59.0
	4/21/81	68.0
	4/30/81	68.6
	5/06/81	70.6
	5/13/81	71.0
LWA115	3/13/80	67.0
	8/20/80	60.0
	10/27/80	55.0
	11/19/80	60.0
	12/16/80	61.0
	1/20/81	45.0
	2/18/81	54.0
	3/17/81	45.4
	5/28/81	34.0
LWA121	5/08/80	23.0
	8/06/80	50.0
	9/04/80	45.0
	5/18/81	40.0
LWD108	7/24/80	250.0
	8/20/80	280.0
	10/27/80	315.0
	11/19/80	171.0
	12/16/80	165.0
	1/20/81	167.0
	2/18/81	235.0
	3/17/81	232.2
	4/02/81	226.2
	4/09/81	231.3
	4/16/81	234.1
	4/21/81	235.7
	4/30/81	237.7
	5/06/81	232.0
	5/13/81	214.0

Logan Wash Flume Flow Data

ON Time - 10/15/80	
10/15/80	0.00
10/16	0.13
10/17	0.02
10/18	0.00
10/19	0.00
10/20	0.00
10/21	0.00
10/22	0.00
10/23	0.00
10/24	0.00
10/25	0.00
OFF - 10/25/80	

NO FLOW DURING WINTER SEASON

ON Time - 4/14/81, 1600	
4/14/81	0.01
4/15	0.11
4/16	0.00
4/17	0.00
4/18	0.00
4/19	0.00
4/20	0.00
4/21	0.00
4/22/81	0.25
4/23	0.70
4/24	0.00
4/25	0.22
4/26	0.00
4/27	0.00
4/28	0.00
4/29	0.00
4/30	0.00
5/1/81	0.00
5/2	0.00
5/3	0.00
5/4	0.00
5/5	0.00
5/6	0.00
5/7	0.00
5/8	0.00
5/9	0.34
5/10	0.00
5/11	0.00
5/12	0.00
5/13	0.00
5/14	0.00
5/15	0.00
OFF - 5/15/81	

LOGAN WASH
WATER QUALITY PARAMETERS
ALLUVIAL WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	CA (MG/L)	B (MG/L)	CU (MG/L)	V (MG/L)	MO (MG/L)	LI (MG/L)	ZN (MG/L)	AL (MG/L)	BA (MG/L)	SR (MG/L)	AMMONIA AS N (MG/L)
LWA022	80	1	17	270.0	.400	-.020	-.050	.030	.100	-.020	-.100	-.500	9.00	.50
		2	13	180.0	.200	-.010	-.050	.040	.100	.010	-.100	.500	9.30	.05
		3	13	240.0	.300	.020	-.050	.030	.100	-.020	-.100	-.500	6.60	-.04
		4	21	270.0	.300	.020	-.050	.070	.100	.020	-.100	.500	.60	.09
		5	22	190.0	.400	.040	-.050	.100	.100	.030	-.100	.800	3.80	.20
		6	19	240.0	.400	.060	-.050	.100	.100	.020	-.100	-.500	5.60	-.04
		7	24	220.0	.300	-.020	-.050	.100	.100	-.020	-.100	-.500	8.60	-.04
		8	20	210.0	.400	.020	-.050	.100	.200	-.020	-.100	-.500	5.40	.70
		10	22	230.0	.600	.060	-.050	.100	.100	-.020	-.100	-.500	5.20	-.04
		11	19	270.0	.400	-.020	-.050	.100	.100	-.020	-.100	-.500	4.60	-.04
		12	9	260.0	.400	-.020	-.050	.100	.100	-.020	-.100	-.500	4.70	-.04
	81	1	20	240.0	.500	.020	-.050	.060	.100	-.020	-.100	-.500	4.60	.20
		2	18	220.0	2.800	-.020	-.050	.070	.100	-.020	-.100	-.500	3.90	-.04
		3	17	200.0	.400	-.020	-.050	.070	.100	-.020	-.100	-.500	4.20	-.04
LWA100	80	11	19	220.0	2.500	-.020	-.050	.700	.100	-.020	-.100	-.500	5.60	-.04
		12	9	200.0	2.600	.020	-.050	.800	.100	-.020	-.100	-.500	6.50	-.04
	81	2	18	200.0	.400	.040	-.050	.600	.200	-.020	-.100	-.500	6.20	.20
		3	17	200.0	2.900	-.020	-.050	.600	.100	-.020	-.100	-.500	5.90	-.04
		4	2						.100					.05
			9						.100					.07
			16						.100					.10
			23						.100					.20
LWA101	80	1	17	150.0	2.000	-.020	-.050	.400	.100	-.020	-.100	-.500	9.20	-.04
		2	13	130.0	2.200	-.010	-.050	.400	.100	.020	.200	.500	11.00	-.04
		3	13	160.0	1.500	.020	-.050	.300	.100	.020	-.100	.500	7.60	.20
		4	21	240.0	1.000	.030	-.050	.400	.100	.020	-.100	.500	.70	2.00
		5	22	140.0	.800	.080	-.050	.200	.090	.030	-.100	.500	3.80	.40
		6	19	160.0	1.300	.040	-.050	.600	.100	.010	-.100	-.500	4.70	.20
		7	24	69.0	1.300	-.020	-.050	.600	.100	-.020	-.100	-.500	7.20	1.00
		8	20	150.0	1.500	.030	-.050	.700	.100	-.020	-.100	-.500	5.20	2.60
		10	22	140.0	2.100	.050	-.050	.700	.100	-.020	-.100	-.500	5.40	.10
LWA102	80	1	9	130.0	.400	-.020	-.050	.200	.200	.020	-.100	-.500	6.30	-.04
		2	7	110.0	.300	-.020	-.050	.200	.200	.020	-.100	-.500	6.00	-.04
		3	6	160.0	.500	.020	-.050	.200	.100	-.020	-.100	.500	3.60	-.04
		4	10	190.0	.300	-.020	-.050	.200	.200	.030	-.100	.500	.30	-.04
		5	8	200.0	.100	.040	-.050	.200	.200	.030	-.100	.700	3.50	-.04
		6	3	140.0	.300	.060	-.050	.200	.100	.040	-.100	-.500	4.20	-.04
		7	3	160.0	.500	-.020	-.050	.400	.200	-.010	-.100	-.500	3.50	.05
		8	6	150.0	.400	-.020	-.050	.200	.200	-.020	-.100	-.500	4.80	.08
		9	4	140.0	.400	-.020	-.050	.300	.200	-.020	-.100	-.500	2.40	.05
		10	2	180.0	.400	.020	-.050	.200	.200	.060	-.100	-.500	2.50	.20

LOGAN WASH
WATER QUALITY PARAMETERS
ALLUVIAL WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	CA (MG/L)	B (MG/L)	CU (MG/L)	V (MG/L)	MO (MG/L)	LI (MG/L)	ZN (MG/L)	AL (MG/L)	BA (MG/L)	SR (MG/L)	AMMONIA AS N (MG/L)
LWA102	80	11	6	180.0	.400	-.020	-.050	.100	.200	-.020	-.100	-.500	3.10	-.04
		12	4	200.0	.400	-.020	-.050	.200	.200	-.020	-.100	-.500	3.20	-.04
LWA103	80	1	16	200.0	.200	-.020	-.050	.090	.100	.020	.400	-.500	5.00	.20
		4	23	270.0	.200	.020	-.050	.070	.090	.020	-.100	-.500	.40	.10
		7	23	230.0	.200	-.020	-.050	.100	.100	-.020	-.100	-.500	6.50	.05
		10	16	270.0	.300	-.020	-.050	.100	.100	-.020	-.100	-.500	6.30	-.04
	81	1	29	200.0	.400	-.020	-.050	-.010	.100	-.020	-.100	-.500	2.00	.10
LWA104	80	1	16	340.0	.900	-.020	.010	-.010	.200	.030	-.100	.500	8.50	-.04
		7	23	74.0	.500	-.020	-.050	-.010	.200	-.020	-.100	-.500	5.40	1.40
		10	16	150.0	.300	-.020	-.050	-.010	.090	-.020	-.100	-.500	3.60	.07
	81	1	29	290.0	.300	-.020	-.050	.100	.100	-.020	-.100	-.500	7.10	.20
LWA112	80	5	28	64.0	1.700	.100	-.050	.800	.100	.080	-.100	-.500	1.90	-.04
		6	19	98.0	2.000	.030	-.050	.700	.100	.010	-.100	-.500	3.10	1.10
		7	24	120.0	1.700	-.020	-.050	.800	.100	-.020	-.100	-.500	5.30	.40
		8	19	72.0	1.400	-.020	-.050	.600	.200	-.020	-.100	-.500	3.20	5.80
		10	22	59.0	1.800	.030	-.050	.500	.100	-.020	-.100	-.500	3.00	9.00
		11	19	97.0	1.900	-.020	-.050	.400	.200	-.020	-.100	-.500	3.50	7.60
		12	9	97.0	1.800	-.020	-.050	.500	.200	-.020	-.100	-.500	3.80	9.10
	81	3	17	80.0	1.700	-.020	-.050	.100	.200	-.020	-.100	-.500	2.80	17.00
		4	30						.100					9.80
LWA115	80	1	17	150.0	.100	-.020	-.050	.060	.100	.020	-.100	-.500	6.30	.08
		2	13	120.0	.400	-.010	-.050	.060	.100	.020	.400	-.500	7.20	.05
		3	13	280.0	.400	.020	-.050	.040	.100	.020	-.100	.500	9.40	.20
		7	24	220.0	.400	-.020	-.050	.090	.200	-.020	-.100	-.500	8.90	-.04
		8	20	240.0	.700	.030	-.050	.080	.200	.020	-.100	-.500	6.30	.05
		10	22	160.0	.400	.050	-.050	.100	.100	-.020	-.100	-.500	4.30	.10
		11	19	210.0	.400	-.020	-.050	.050	.200	-.020	-.100	-.500	4.00	-.04
		12	9	250.0	.400	-.020	-.050	.070	.200	-.020	-.100	-.500	5.00	-.04
	81	1	20	93.0	.500	-.020	-.050	.040	.600	-.020	-.100	-.500	5.30	
		2	18	250.0	.700	-.020	-.050	.040	.200	-.020	-.100	-.500	4.70	-.04
		3	17	220.0	.700	-.020	-.050	.040	.100	.020	-.100	-.500	4.70	-.04
LWA121	80	5	8	160.0	.200	-.010	-.050	.030	.100	.030	-.100	.700	3.00	-.04
		7	3	110.0	.300	.030	-.050	.200	.100	.010	-.100	-.500	3.00	.10
		8	6	120.0	.300	-.020	-.050	.100	.100	.020	-.100	-.500	4.50	.20
		9	4	120.0	.200	.020	-.050	.100	.100	-.020	-.100	-.500	2.30	1.50

LOGAN WASH
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LOC	YR	MO	DY	FECAL COLIF COLONY /100 ML	TOTAL COLIF COLONY /100 ML	SO3 (MG/L)	N KJELD. (MG/L)	FE (MG/L)	MG (MG/L)	AG (MG/L)	TOC (MG/L)	ALPHA (PCI/1)	BETA (PCI/1)	RADIUM 226 (PCI/1)
LWA022	80	1	17					1.900	170.0			15.00	2.00	
		2	13				.30	.100	140.0			18.00	21.00	.35
		3	13				2.70	-.020	130.0			56.00	19.00	.40
		4	21				.70	.030	180.0			6.90	14.00	
		5	22				1.30	.020	150.0			24.00	4.70	
		6	19				1.10	.030	160.0					
		7	24				1.00	.020	180.0					
		8	20				1.30	.030	180.0			18.00	9.50	
		10	22				.07	.030	260.0				29.00	.94
		11	19				1.80	.060	220.0			15.00	11.00	
		12	9				.80	.030	290.0			21.60	11.50	.45
	81	1	20				2.50	.030	180.0					
		2	18				.70	-.020	180.0					
		3	17				1.10	.020	170.0					
LWA100	80	11	19				2.00	.050	250.0			26.00	24.00	1.30
		12	9				2.80	.030	230.0			40.80	28.20	14.70
	81	2	18				2.60	.020	260.0					
		3	17				2.80	.030	230.0					
		4	2											
			9											
			16											
			23											
LWA101	80	1	17					.100	190.0			18.00	53.00	.33
		2	13				2.20	.090	190.0			62.00	168.00	.66
		3	13				3.90	-.020	160.0			21.00	8.00	
		4	21				4.20	.030	210.0			8.00	14.00	
		5	22				2.70	.020	160.0			28.00	10.00	1.20
		6	19				2.50	.030	140.0					
		7	24				1.10	-.020	120.0					
		8	20				11.00	.020	170.0			13.00	20.00	.19
		10	22				.30	.030	220.0				8.30	
LWA102	80	1	9	-1.0	-1.00		-1.00	-.020	96.0	-.010	5.0	15.00	69.00	.30
		2	7				.07	.020	91.0			8.90	12.00	
		3	6				.60	-.020	79.0			9.40	22.00	1.40
		4	10				.70	.030	95.0			46.00	21.00	4.50
		5	8				1.10	-.020	89.0			13.00	22.00	.62
		6	3				.40	.020	80.0			14.00	11.00	
		7	3				.30	.030	92.0			21.00	26.00	
		8	6				.80	-.020	87.0			14.80	22.80	2.10

LOGAN WASH
WATER QUALITY PARAMETERS
ALLUVIAL WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	FECAL COLIF COLONY /100 ML	TOTAL COLIF COLONY /100 ML	SO3 (MG/L)	N KJELD. (MG/L)	FE (MG/L)	MG (MG/L)	AG (MG/L)	TOC (MG/L)	ALPHA (PCI/1)	BETA (PCI/1)	RADIUM 226 (PCI/1)
LWA102	80	10	2				.60	.030	89.0				19.00	.36
		11	6				-.10	.020	100.0			26.00	21.00	2.20
		12	4				-.10	-.020	110.0			8.10	5.70	
LWA103	80	1	16					1.700	120.0			29.00	13.00	.73
		4	23				.10	.020	130.0			32.00	33.00	1.10
		7	23				.07	-.020	120.0			36.00	10.90	.80
		10	16				.30	.020	120.0				16.00	
	81	1	29				.40	5.900	180.0					
LWA104	80	1	16					57.000	480.0			23.00	19.00	.49
		7	23				2.00	.020	250.0			7.20	6.60	
		10	16				.60	-.020	150.0				14.00	
	81	1	29				.30	.020	150.0					
LWA112	80	5	28				1.50	.020	82.0			13.00	9.60	
		6	19				3.20	.020	100.0					
		7	24				6.80	-.020	100.0					
		8	19				6.70	.020	120.0			13.00	21.00	1.00
		10	22				12.00	.030	160.0				9.90	
		11	19				11.00	.070	170.0			7.20	19.00	
		12	9				12.00	-.020	160.0				14.60	
	81	3	17				21.00	.200	150.0					
		4	30											
LWA115	80	1	17					.070	160.0			4.60	11.00	
		2	13				.10	.100	140.0			22.00	7.00	
		3	13				1.50	-.020	190.0			48.00	11.00	.64
		7	24				.40	-.020	170.0					
		8	20				1.60	.020	220.0			50.00	11.00	1.00
		10	22				.10	.030	210.0				17.00	
		11	19				1.50	.040	180.0			14.00	14.00	
		12	9				.30	.030	310.0			15.40	5.30	
	81	1	20				1.70	.040	78.0					
		2	18				1.80	-.020	250.0					
		3	17				1.60	.020	200.0					
LWA121	80	5	8				.40	-.020	91.0			12.00	11.00	
		7	3				.30	.030	96.0			59.00	19.00	
		8	6				1.10	-.020	98.0			12.40	8.90	
		9	4				1.70	.050	96.0			17.00	15.00	.84

LOGAN WASH
WATER QUALITY PARAMETERS
ALLUVIAL WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	S203 (MG/L)	HG (MG/L)	SE (MG/L)	SO4 (MG/L)	CL (MG/L)	F (MG/L)	SI (MG/L)	NO3 (MG/L)	NA (MG/L)	K (MG/L)	AS (MG/L)
LWA022	80	1	17				2100.00	56.00	.70		62.00	500.0	13.00	-.020
		2	13	-1.00			1600.00	42.00	.80		59.00	410.0	7.00	-.020
		3	13			.010	1400.00	78.00	1.00		120.00	350.0	17.00	-.020
		4	21			.020	1200.00	78.00	.60		81.00	240.0	7.40	-.020
		5	22			.090	1100.00	91.00	.80		100.00	220.0	7.70	-.020
		6	19			-.010	1200.00	32.00	.90		58.00	250.0	7.80	-.020
		7	24			.010	1600.00	29.00	1.00		66.00	290.0	13.00	-.020
		8	20			.010	1500.00	23.00	1.40		58.00	280.0	9.20	-.050
		10	22			.010	1800.00	29.00	.20		51.00	340.0	20.00	-.020
		11	19			.020	1400.00	29.00	1.00	17.0	61.00	240.0	11.00	-.020
		12	9			-.010	1300.00	30.00	.80	16.0	67.00	260.0	12.00	-.020
	81	1	20			.020	1300.00	33.00	1.30	15.0	69.00	250.0	14.00	-.020
		2	18			-.010	1100.00	31.00	.90	13.0	66.00	230.0	12.00	-.020
		3	17			-.010	1000.00	29.00	.80	14.0	68.00	250.0	12.00	-.020
LWA100	80	11	19			.020	1400.00	81.00	.90	18.0	180.00	310.0	12.00	-.020
		12	9			.010	1400.00	84.00	.80	17.0	190.00	350.0	13.00	-.020
	81	2	18			-.010	1400.00	93.00	.80	13.0	160.00	340.0	15.00	-.020
		3	17			.020	1400.00	86.00	.70	14.0	180.00	370.0	17.00	-.020
		4	2											
			9											
			16											
			23											
LWA101	80	1	17				1300.00	110.00	.70		170.00	280.0	11.00	-.020
		2	13	-1.00			1200.00	72.00	.80		170.00	320.0	10.00	-.020
		3	13			.040	1200.00	86.00	1.00		190.00	310.0	9.90	-.020
		4	21			.050	1300.00	100.00	.40		230.00	290.0	9.50	-.020
		5	22			.040	1100.00	120.00	.70		230.00	230.0	7.50	-.020
		6	19			.010	940.00	38.00	1.00		140.00	280.0	7.90	-.020
		7	24			.010	980.00	45.00	1.10		120.00	270.0	7.30	-.020
		8	20			.020	1200.00	52.00	1.80		170.00	310.0	8.30	-.020
		10	22			.020	1400.00	70.00	.20		180.00	310.0	8.60	-.020
LWA102	80	1	9	-1.00	-.020	-.020	890.00	16.00	1.40	14.0	3.00	230.0	18.00	-.020
		2	7	-1.00		-.002	890.00	21.00	1.50		18.00	220.0	18.00	-.020
		3	6			-.020	910.00	30.00	1.60		11.00	270.0	17.00	-.020
		4	10			.020	890.00	78.00	1.50		28.00	200.0	16.00	-.020
		5	8			.050	900.00	56.00	1.50		13.00	210.0	17.00	-.020
		6	3			.080	860.00	61.00	1.30		8.00	210.0	16.00	-.020
		7	3			-.010	900.00	14.00	2.20		8.60	230.0	18.00	-.020
		8	6			-.010	920.00	16.00	1.30		6.70	220.0	16.00	-.020
		9	4			-.010	920.00	12.00	2.90		11.00	230.0	17.00	-.020
		10	2			-.010	920.00	13.00	1.30		8.90	220.0	17.00	-.020
		11	6			.010	950.00	13.00	2.40	16.0	9.10	220.0	20.00	-.020

LOGAN WASH
WATER QUALITY PARAMETERS
ALLUVIAL WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	S2O3 (MG/L)	HG (MG/L)	SE (MG/L)	SO4 (MG/L)	CL (MG/L)	F (MG/L)	SI (MG/L)	NO3 (MG/L)	NA (MG/L)	K (MG/L)	AS (MG/L)
LWA102	80	12	4			-.010	960.00	14.00	1.30	15.0	11.00	240.0	18.00	-.020
LWA103	80	1	16				1200.00	35.00	1.10		130.00	250.0	7.30	-.020
		4	23			.040	1100.00	50.00	.90		31.00	220.0	5.50	-.020
		7	23			.010	1400.00	9.60	1.40		10.00	260.0	4.40	-.020
		10	16			.010	1300.00	10.00	1.40		6.00	260.0	4.40	.300
	81	1	29			-.010	1300.00	11.00	1.30	13.0	2.70	550.0	8.30	-.020
LWA104	80	1	16				6400.00	73.00	.60		330.00	1800.0	8.00	-.020
		7	23			.050	3700.00	29.00	.80		-.50	1100.0	4.40	-.020
		10	16			.020	1300.00	18.00	.90		-.50	410.0	2.50	-.020
	81	1	29			-.010	2100.00	24.00	.90	2.0	5.10	280.0	9.30	-.020
LWA112	80	5	28			.030	670.00	91.00	1.00		98.00	190.0	8.40	-.020
		6	19			-.010	660.00	43.00	1.20		34.00	240.0	11.00	-.020
		7	24			-.010	850.00	55.00	1.10		2.40	260.0	11.00	-.020
		8	19			-.010	910.00	55.00	1.60		1.30	280.0	12.00	-.020
		10	22			-.010	890.00	64.00	.30		-.50	260.0	11.00	.020
		11	19			.020	960.00	69.00	.80	4.3	-.50	260.0	14.00	-.020
		12	9			-.010	970.00	72.00	.80	3.5	-.50	280.0	16.00	-.020
	81	3	17			.010	810.00	71.00	.60	2.5	1.00	290.0	20.00	
		4	30											
LWA115	80	1	17				1200.00	23.00	.80		4.00	300.0	6.70	-.020
		2	13	-1.00			1200.00	25.00	.90		-.10	340.0	5.20	-.020
		3	13			.020	1800.00	63.00	1.00		61.00	380.0	8.00	-.020
		7	24			.020	1600.00	17.00	1.00		55.00	340.0	5.20	-.020
		8	20			.030	1900.00	14.00	.50		66.00	490.0	5.50	-.020
		10	22			.020	1400.00	15.00	-.10		32.00	340.0	4.90	-.020
		11	19			.020	1300.00	15.00	1.00	18.0	22.00	320.0	6.20	-.020
		12	9			.010	1600.00	16.00	.90	28.0	20.00	370.0	8.40	-.020
	81	1	20			.020	2000.00	20.00	1.30	18.0	41.00	650.0	9.30	-.020
		2	18			-.010	1800.00	26.00	1.00	12.0	31.00	440.0	12.00	-.020
		3	17			.020	1600.00	22.00	.80	14.0	28.00	430.0	13.00	-.020
LWA121	80	5	8			.030	640.00	45.00	.90		12.00	160.0	7.00	-.020
		7	3			-.010	650.00	11.00	2.40		11.00	160.0	7.20	-.020
		8	6			-.010	700.00	16.00	.80		18.00	170.0	4.40	-.020
		9	4			-.010	700.00	12.00	2.10		12.00	180.0	5.40	-.020

LOGAN WASH
WATER QUALITY PARAMETERS
ALLUVIAL WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	TOT ALK (MG/L CACO3)	HCO3 (MG/L CACO3)	CO3 (MG/L CACO3)	TDS (MG/L)	TOT. SUSP. SOLID (MG/L)	TURB. NTU	COD (MG/L)	PHEN (MG/L)	BOD5 (MG/L)	DOC (MG/L)	OIL AND GREASE (MG/L)
LWA022	80	1	17	400.0	400.0	-1.0	3600.0	110.0	75.0	1.0	.002	130.00		-1.00
		2	13	350.0	350.0	-1.0	2900.0	130.0	65.0	25.0	-.001	-1.00	7.00	16.00
		3	13	490.0	490.0	-1.0	2800.0	270.0	68.0	5.0	.004	12.00	18.00	1.00
		4	21	470.0	470.0	-1.0	2400.0	190.0	47.0	2.0	-.001	2.00	40.00	10.00
		5	22	430.0	390.0	40.0	2300.0	150.0	62.0	2.0	-.001	17.00		1.00
		6	19	430.0	430.0	-1.0	2400.0	80.0	32.0	40.0	.003	8.00		5.00
		7	24	480.0	480.0	-1.0	2900.0	160.0	38.0	30.0	-.001	40.00		4.00
		8	20	450.0	450.0	-1.0	2700.0	43.0	32.0	30.0	.030	32.00		2.00
		10	22	540.0	540.0	-1.0	3400.0	400.0	49.0	80.0	.009	2.00	45.00	3.00
		11	19	450.0	450.0	-1.0	2600.0	970.0	170.0	26.0	.001	35.00	42.00	4.00
		12	9	440.0	440.0	-1.0	2500.0	580.0	56.0	2.0	.001	28.00	52.00	2.00
	81	1	20	420.0	420.0	-1.0	2500.0	1,300.0	40.0	75.0	.012		36.00	-1.00
		2	18	450.0	450.0	-1.0	2200.0	630.0	95.0	40.0	.001	340.00	40.00	8.00
		3	17	450.0	450.0	-1.0	2100.0	76.0	48.0	13.0	-.001	65.00	30.00	3.00
LWA100	80	11	19	400.0	400.0	-1.0	2900.0	330.0	86.0	56.0	.004	57.00	48.00	-1.00
		12	9	400.0	400.0	-1.0	2900.0	520.0	180.0	48.0	-.001	50.00	43.00	2.00
	81	2	18	420.0	420.0	-1.0	3000.0	350.0	95.0	60.0	.003	340.00	50.00	5.00
		3	17	430.0	430.0	-1.0	2900.0	-1.0	12.0	40.0	.001	35.00	45.00	3.00
		4	2								.005			
			9								-.001			
			16								-.001			
			23								-.001			
LWA101	80	1	17	430.0	430.0	-1.0	2700.0	200.0	58.0	38.0	.005	37.00		20.00
		2	13	400.0	400.0	-1.0	2600.0	39.0	23.0	68.0	-.001	5.00	10.00	4.00
		3	13	440.0	440.0	-1.0	2600.0	32.0	41.0	14.0	-.001	15.00	22.00	8.00
		4	21	430.0	430.0	-1.0	2700.0	160.0	96.0	54.0	-.001	10.00	60.00	16.00
		5	22	420.0	420.0	-1.0	2400.0	34.0	34.0	27.0	-.001	19.00		6.00
		6	19	390.0	390.0	-1.0	2100.0	240.0	73.0	20.0	.006	1.00		7.00
		7	24	390.0	390.0	-1.0	2100.0	99.0	47.0	56.0	-.001	5.00		9.00
		8	20	380.0	380.0	-1.0	2500.0	120.0	33.0	64.0	.040	60.00		2.00
		10	22	420.0	420.0	-1.0	2700.0	220.0	50.0	60.0	.010	16.00	56.00	4.00
LWA102	80	1	9	340.0	340.0	-1.0	1700.0	38.0	23.0	4.0	-.001	50.00	2.00	11.00
		2	7	360.0	360.0	-1.0	1700.0	5.0	16.0	2.0	.002	5.00	6.00	9.00
		3	6	340.0	340.0	-1.0	1700.0	120.0	58.0	26.0	-.001	5.00	7.00	24.00
		4	10	350.0	300.0	50.0	1700.0	17.0	18.0	13.0	.001	34.00	10.00	11.00
		5	8	350.0	350.0	-1.0	1800.0	140.0	34.0	5.0	.003	10.00		12.00
		6	3	360.0	360.0	-1.0	1700.0	1.0	1.0	2.0	-.001	17.00		4.00
		7	3	350.0	350.0	-1.0	1700.0	120.0	390.0	6.0	-.001	55.00		4.00
		8	6	360.0	360.0	-1.0	1800.0	94.0	36.0	6.0	.001	29.00		3.00
		9	4	370.0	370.0	-1.0	1800.0	210.0	53.0	5.0	.010	5.00		4.00
		10	2	350.0	350.0	-1.0	1800.0	97.0	41.0	16.0	-.001	9.00	42.00	2.00

LOGAN WASH
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ALLUVIAL WELLS
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LOC	YR	MO	DY	TOT ALK (MG/L CACO3)	HCO3 (MG/L CACO3)	CO3 (MG/L CACO3)	TDS (MG/L)	TOT. SUSP. SOLID (MG/L)	TURB. NTU	COD (MG/L)	PHEN (MG/L)	BOD5 (MG/L)	DOC (MG/L)	OIL AND GREASE (MG/L)
LWA102	80	11	6	360.0	360.0	-1.0	1800.0	84.0	36.0	2.0	-.001	10.00	29.00	4.00
		12	4	350.0	350.0	-1.0	1800.0	200.0	33.0	-1.0	.002	16.00	19.00	3.00
LWA103	80	1	16	350.0	350.0	-1.0	2200.0	210.0	140.0	2.0	.003	19.00		5.00
		4	23	420.0	420.0	-1.0	2200.0	960.0	160.0	2.0	-.001	1.00		9.00
		7	23	400.0	400.0	-1.0	2500.0	380.0	62.0	24.0	-.001	26.00		1.00
		10	16	400.0	400.0	-1.0	2400.0	860.0	140.0	20.0	-.001	57.00	50.00	3.00
	81	1	29	370.0	370.0	-1.0	2300.0	520.0	140.0	10.0	-.001	34.00	22.00	1.00
LWA104	80	1	16	240.0	240.0	-1.0	10000.0	250.0	98.0	52.0	.013	35.00		4.00
		7	23	390.0	390.0	-1.0	6200.0	210.0	58.0	34.0	-.001	19.00		-1.00
		10	16	390.0	390.0	-1.0	2300.0	2.0	130.0	8.0	-.001	51.00	45.00	-1.00
	81	1	29	140.0	140.0	-1.0	3300.0	260.0	160.0	21.0	.008	580.00	31.00	6.00
LWA112	80	5	28	310.0	290.0	20.0	1400.0	20.0	16.0	51.0	.015	10.00		1.00
		6	19	320.0	290.0	28.0	1400.0	76.0	48.0	40.0	.005	40.00		9.00
		7	24	350.0	300.0	48.0	1700.0	750.0	160.0	160.0	-.001	14.00		14.00
		8	19	330.0	290.0	44.0	1800.0	1,600.0	180.0	120.0	.040	190.00		-1.00
		10	22	380.0	380.0	-1.0	1900.0	18,000.0	*****	140.0	.020	290.00	110.00	5.00
		11	19	370.0	310.0	60.0	1900.0	1,000.0	220.0	170.0	.001	210.00	84.00	4.00
		12	9	360.0	330.0	34.0	1900.0	5,200.0	75.0	240.0	.002	190.00	58.00	2.00
	81	3	17	460.0	460.0	-1.0	1800.0	4,900.0	850.0	740.0	.023	300.00	240.00	2.00
		4	30								.002			
LWA115	80	1	17	530.0	530.0	-1.0	2600.0	94.0	34.0	-1.0	-.001	32.00		19.00
		2	13	540.0	540.0	-1.0	2200.0	140.0	48.0	35.0	-.001	.10	3.00	10.00
		3	13	530.0	530.0	-1.0	3700.0	7.0	22.0	-1.0	.025	20.00	8.00	1.00
		7	24	530.0	530.0	-1.0	3100.0	400.0	88.0	20.0	-.001	10.00		1.00
		8	20	510.0	510.0	-1.0	3500.0	450.0	160.0	21.0	.040	54.00		3.00
		10	22	550.0	550.0	-1.0	2800.0	920.0	250.0	24.0	.008	3.00	44.00	4.00
		11	19	560.0	560.0	-1.0	2300.0	880.0	250.0	210.0	-.001	36.00	47.00	5.00
		12	9	550.0	550.0	-1.0	3000.0	280.0	140.0	2.0	-.001	30.00	48.00	5.00
	81	1	20	550.0	550.0	-1.0	3800.0	260.0	88.0	13.0	.012		22.00	-1.00
		2	18	570.0	570.0	-1.0	3400.0	240.0	90.0	200.0	.003	42.00	88.00	3.00
		3	17	540.0	540.0	-1.0	3000.0	310.0	200.0	48.0	.008	40.00	45.00	3.00
LWA121	80	5	8	490.0	490.0	-1.0	2000.0	260.0	56.0	2.0	-.001	12.00		8.00
		7	3	450.0	450.0	-1.0	1400.0	430.0	78.0	14.0	-.001	41.00		2.00
		8	6	450.0	450.0	-1.0	1500.0	490.0	83.0	14.0	-.001	60.00		1.00
		9	4	470.0	470.0	-1.0	1500.0	2,700.0	60.0	8.0	.020	31.00		14.00

LOGAN WASH
WATER QUALITY PARAMETERS
DEEP WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	CA (MG/L)	B (MG/L)	CU (MG/L)	V (MG/L)	MO (MG/L)	LI (MG/L)	ZN (MG/L)	AL (MG/L)	BA (MG/L)	SR (MG/L)	AMMONIA AS N (MG/L)
LWD032	80	9	16	48.0	.400	.020	-.050	.020	-.050	-.020	-.100	-.500	3.70	-.04
		12	4	67.0	-.100	-.020	-.050	.020	-.050	-.020	-.100	-.500	5.00	-.04
LWD046	80	9	18	15.0	.100	-.020	-.050	-.010	.090	-.020	-.100	-.500	3.50	-.04
		12	4	19.0	.100	-.020	-.050	-.010	.090	-.020	-.100	-.500	4.50	-.04
LWD047	80	9	18	63.0	-.100	-.020	-.050	.010	-.050	-.020	-.100	-.500	5.30	-.04
		12	4	84.0	-.100	-.020	-.050	.010	-.050	-.020	-.100	-.500	6.20	-.04
LWD106	80	7	17	46.0	.200	-.020	-.050	.050	.070	-.010	-.100	-.500	13.00	.05
		9	16	66.0	.200	.020	-.050	.080	.080	-.020	-.100	-.500	10.00	.20
LWD108	80	1	10	57.0	2.500	-.020	-.050	.020	.700	-.020	-.100	-.500	7.20	1.70
		2	14	53.0	.300	-.010	-.050	.070	.700	.010	-.100	-.500	9.30	1.60
		3	20	70.0	15.000	.020	-.050	.200	.500	.040	-.100	-.500	3.30	1.70
		4	16	100.0	14.000	-.020	-.050	.600	.500	.030	-.100	-.500	.60	1.70
		6	19	97.0	8.200	.050	-.050	.400	.700	.040	-.100	-.500	6.30	1.90
		7	24	74.0	8.500	-.020	-.050	.090	.700	-.020	-.100	-.500	9.20	1.00
		8	20	71.0	9.200	.030	-.020	.050	.900	-.020	-.100	-.500	5.90	.60
		10	22	65.0	13.000	.030	-.050	.200	.700	-.020	-.100	-.500	4.80	.60
		11	19	87.0	14.000	-.020	-.050	.060	.700	-.020	-.100	-.500	5.10	1.50
		12	16	86.0	16.000	-.020	-.050	.050	.600	-.020	-.100	-.500	5.30	3.90
	81	1	20	280.0	18.000	-.020	-.050	.030	.200	-.020	-.100	-.500	5.90	2.20
		2	18	82.0	18.000	-.020	-.050	.100	.600	-.020	-.100	-.500	4.50	2.00
		3	17	90.0	17.000	-.020	-.050	.200	.500	-.020	-.100	-.500	5.40	6.30
		4	2						.500					8.30
			9						.500					7.20
			16						.500					7.20
			23						.400					7.70
			30						.400					7.00
LWD116	80	9	16	70.0	-.100	.020	-.050	.020	-.050	-.020	-.100	-.500	1.20	.04

LOGAN WASH
WATER QUALITY PARAMETERS
DEEP WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	FECAL COLIF COLONY /100 ML	TOTAL COLIF COLONY /100 ML	SO3 (MG/L)	N KJELD. (MG/L)	FE (MG/L)	MG (MG/L)	AG (MG/L)	TOC (MG/L)	ALPHA (PCI/1)	BETA (PCI/1)	RADIUM 226 (PCI/1)
LWD032	80	9	16				.60	.020	15.0					
		12	4				-.10	-.020	23.0					
LWD046	80	9	18				.60	-.020	14.0					
		12	4				-.10	-.020	18.0					
LWD047	80	9	18				-.10	-.020	27.0					
		12	4				-.10	-.020	34.0					
LWD106	80	7	17				6.60	-.020	28.0					
		9	16				.30	-.020	45.0					
LWD108	80	1	10	-1.0	-1.00		3.20	.070	62.0	-.010	137.0	6.00	62.00	
		2	14				3.40	-.020	63.0			5.00	4.00	
		3	20				3.20	-.020	48.0			22.00		
		4	16				5.10	.020	83.0					
		6	19				1.90	-.020	66.0					
		7	24				1.40	.020	64.0					
		8	20				2.00	.020	69.0					
		10	22				.60	.050	76.0					
		11	19				2.90	.050	86.0					
		12	16				3.90	-.020	75.0					
	81	1	20				4.20	.040	240.0					
		2	18				4.20	.060	84.0					
		3	17				11.00	.040	90.0					
		4	2											
			9											
			16											
			23											
			30											
LWD116	80	9	16				.80	-.020	21.0		-.5			

LOGAN WASH
WATER QUALITY PARAMETERS
DEEP WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	S203 (MG/L)	HG (MG/L)	SE (MG/L)	SO4 (MG/L)	CL (MG/L)	F (MG/L)	SI (MG/L)	NO3 (MG/L)	NA (MG/L)	K (MG/L)	AS (MG/L)
LWD032	80	9	16			-.010	120.00	6.60	.90		-.50	83.0	.70	-.020
		12	4		-.002	-.010	120.00	3.30	.20	23.0	-.50	76.0	.50	-.020
LWD046	80	9	18			-.010	180.00	1.60	1.10		-.50	140.0	.80	-.020
		12	4		-.002	-.010	180.00	2.70	.40	9.8	-.50	150.0	.70	-.020
LWD047	80	9	18			-.010	200.00	2.70	.70		.70	110.0	.80	-.020
		12	4		-.002	-.010	210.00	3.60	.20	26.0	.60	110.0	.60	-.020
LWD106	80	7	17			-.010	260.00	10.00	.30		6.30	140.0	3.30	-.020
		9	16			-.010	380.00	4.40	.80		-.50	140.0	.80	-.020
LWD108	80	1	10	3.90	-.020	-.020	720.00	86.00	7.10		-.10	620.0	4.60	-.020
		2	14	-1.00	-.020	-.020	890.00	100.00	7.90		-.10	750.0	5.00	.020
		3	20			-.010	850.00	140.00	8.10		21.00	610.0	6.80	.020
		4	16			.010	890.00	110.00	8.40		15.00	630.0	5.60	.020
		6	19			-.010	910.00	50.00	5.60		6.70	620.0	5.00	.020
		7	24			.010	900.00	51.00	6.20		.90	580.0	3.10	-.020
		8	20			.030	880.00	47.00	6.20		1.30	610.0	3.60	-.020
		10	22			.010	920.00	14.00	6.20		2.70	670.0	5.20	-.020
		11	19			.030	890.00	61.00	7.10	23.0	1.60	600.0	6.60	-.020
		12	16			.020	850.00	67.00	8.10	22.0	.70	710.0	7.40	-.020
	81	1	20			.020	910.00	82.00	9.90	20.0	.90	450.0	11.00	-.020
		2	18			.010	1000.00	90.00	8.80	16.0	-.50	730.0	11.00	.020
		3	17			.020	1100.00	90.00	8.70	17.0	-.50	810.0	14.00	
		4	2											
			9											
			16											
			23											
			30											
LWD116	80	9	16			-.010	77.00	9.30	.70		.70	46.0	2.20	-.020

LOGAN WASH
WATER QUALITY PARAMETERS
DEEP WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	TOT ALK (MG/L CACO3)	HCO3 (MG/L CACO3)	CO3 (MG/L CACO3)	TDS (MG/L)	TOT. SUSP. SOLID (MG/L)	TURB. NTU	COD (MG/L)	PHEN (MG/L)	BOD5 (MG/L)	DOC (MG/L)	OIL AND GREASE (MG/L)
LWD032	80	9	16	280.0	250.0	28.0	420.0	180.0	41.0	36.0	-.001			10.00
		12	4	230.0	230.0	-1.0	460.0	420.0	50.0	4.0	.004		42.00	3.00
LWD046	80	9	18	280.0	260.0	24.0	500.0	140.0	42.0	12.0	-.001			1.00
		12	4	280.0	280.0	-1.0	550.0	270.0	58.0	8.0	.003		22.00	2.00
LWD047	80	9	18	380.0	380.0	-1.0	600.0	430.0	57.0	14.0	-.001			3.00
		12	4	330.0	330.0	-1.0	640.0	450.0	47.0	4.0	.002		18.00	1.00
LWD106	80	7	17	280.0	250.0	30.0	1000.0	49.0	22.0	2.0	-.001			14.00
		9	16	350.0	350.0	-1.0	910.0	170.0	39.0	-1.0	-.001			1.00
LWD108	80	1	10	920.0	920.0	-1.0	2300.0	46.0	34.0	300.0	-.001	570.00	26.00	5.00
		2	14	950.0	870.0	80.0	2100.0	8.0	16.0	160.0	.006	16.00	39.00	11.00
		3	20	850.0	800.0	56.0	2500.0	30.0	23.0	48.0	.004	19.00		2.00
		4	16	820.0	740.0	80.0	2400.0	15.0	14.0	10.0	.005		46.00	79.00
		6	19	810.0	810.0	-1.0	2900.0	35.0	25.0	190.0	.003			11.00
		7	24	850.0	850.0	-1.0	2200.0	59.0	26.0	60.0	.004			13.00
		8	20	840.0	840.0	-1.0	2200.0	39.0	120.0	32.0	.030			6.00
		10	22	880.0	880.0	-1.0	860.0	110.0	46.0	84.0	.020		52.00	8.00
		11	19	920.0	920.0	-1.0	2400.0	47.0	22.0	68.0	.025		61.00	6.00
		12	16	960.0	960.0	-1.0	2500.0	39.0	24.0	68.0	.003		66.00	2.00
	81	1	20	960.0	960.0	-1.0	2500.0	42.0	17.0	26.0	.009		55.00	1.00
		2	18	990.0	990.0	-1.0	2600.0	110.0	63.0	100.0	.007		79.00	1.00
		3	17	1100.0	1100.0	-1.0	2900.0	48.0	37.0	80.0	.046		64.00	9.00
		4	2								.020			
			9								.050			
			16								.010			
			23								.009			
			30								-.001			
LWD116	80	9	16	320.0	270.0	54.0	490.0	330.0	76.0	4.0	-.001			8.00

LOGAN WASH
WATER QUALITY PARAMETERS
RETORTS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	CA (MG/L)	B (MG/L)	CU (MG/L)	V (MG/L)	MO (MG/L)	LI (MG/L)	ZN (MG/L)	AL (MG/L)	BA (MG/L)	SR (MG/L)	AMMONIA AS N (MG/L)
LWR001	80	1	3	100.0	2.200	-.020	.100	.300	1.200	-.020	-.100	-.500	6.90	13.00
		4	30											.70
		9	18	220.0	3.800	.020	-.050	.070	.600	-.020	-.100	-.500	2.70	2.50
LWR002	80	1	3	3.3	1.000	.020	.200	4.200	.700	-.020	-.100	-.500	1.00	6.30
		4	30	49.0	2.500	.020	.050	.100	.600	.020	-.100	-.500	.60	6.10
LWR004	80	1	2	5.5	2.100	-.020	-.100	.050	1.000	.030	-.100	.500	1.40	320.00
		7	10	7.2	18.000	-.020	-.050	-.010	.900	.010	-.100	-.500	1.10	300.00
		9	18	4.0	26.000	-.020	-.050	-.010	.600	-.020	-.100	-.500	.70	340.00
		12	22	3.2	14.000	-.020	-.050	.020	1.100	-.020	-.100	-.500	.80	240.00
		3	26	4.1	19.0000	-.020	-.050	-.010	.100	.030	-.100	-.500	.90	330.00
LWR005	80	1	2	5.0	1.600	-.020	.100	.040	1.000	-.020	-.100	1.000	.70	400.00
		3	27	3.6	16.000	-.020	-.050	.010	1.100	.020	-.100	-.500	.90	290.00
		7	10	7.6	16.000	-.020	-.050	-.010	.900	-.010	-.100	-.500	.60	170.00
		9	18	1.7	14.000	-.020	-.050	-.010	1.000	-.020	-.100	-.500	-.50	140.00
		12	22	2.4	14.000	.020	-.050	.020	.900	-.020	-.100	-.500	.60	130.00
LWR006	80	1	2	15.0	8.000	-.020	.200	.200	.100	-.020	-.100	.500	5.60	870.00
		3	26	9.8	56.000	-.020	-.050	-.010	.100	.020	-.100	.500	2.40	860.00
		7	10	13.0	23.000	-.020	-.050	1.700	.500	-.010	-.100	-.500	1.50	940.00
		9	18	2.2	9.700	-.020	-.050	-.010	.400	-.020	-.100	-.500	.50	1700.00
		12	22	1.7	23.000	-.020	-.050	.060	.500	-.020	-.100	-.500	.60	550.00

LOGAN WASH
WATER QUALITY PARAMETERS
RETORTS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	FECAL COLIF COLONY /100 ML	TOTAL COLIF COLONY /100 ML	SO3 (MG/L)	N KJELD. (MG/L)	FE (MG/L)	MG (MG/L)	AG (MG/L)	TOC (MG/L)	ALPHA (PCI/1)	BETA (PCI/1)	RADIUM 226 (PCI/1)
LWR001	80	1	3	-1.0	-1.00		17.00	.600	240.0	-.010	37.0	1.50	18.00	
		4	30				1.00							
		9	18				2.80	.030	130.0		18.0			
LWR002	80	1	3	-1.0	-1.00		7.00	.100	.8	-.010	24.0	9.00	191.00	.56
		4	30				12.00	.080	8.0					
LWR004	80	1	2	-1.0	-1.00		190.00	.090	2.2	-.010	220.0		15.00	
		7	10				330.00	.030	3.7					
		9	18				380.00	.030	8.3		250.0			
		12	22				280.00	.050	1.8					
		3	26				330.00	-.020	1.5					
LWR005	80	1	2	-1.0	-1.00		270.00	.080	1.8	-.010	473.0	6.00	82.00	.92
		3	27				300.00	-.020	3.6					
		7	10				210.00	-.020	3.2					
		9	18				170.00	.040	2.0		300.0			
		12	22				170.00	.030	3.0					
LWR006	80	1	2	-1.0	-1.00		410.00	.040	25.0	-.010	360.0	4.50		
		3	26				860.00	-.020	14.0					
		7	10				1000.00	.020	11.0					
		9	18				1800.00	.040	5.0		490.0			
		12	22				750.00	.030	5.3					

LOGAN WASH
WATER QUALITY PARAMETERS
RETORTS
FOR SAMPLE DATA SHOWN

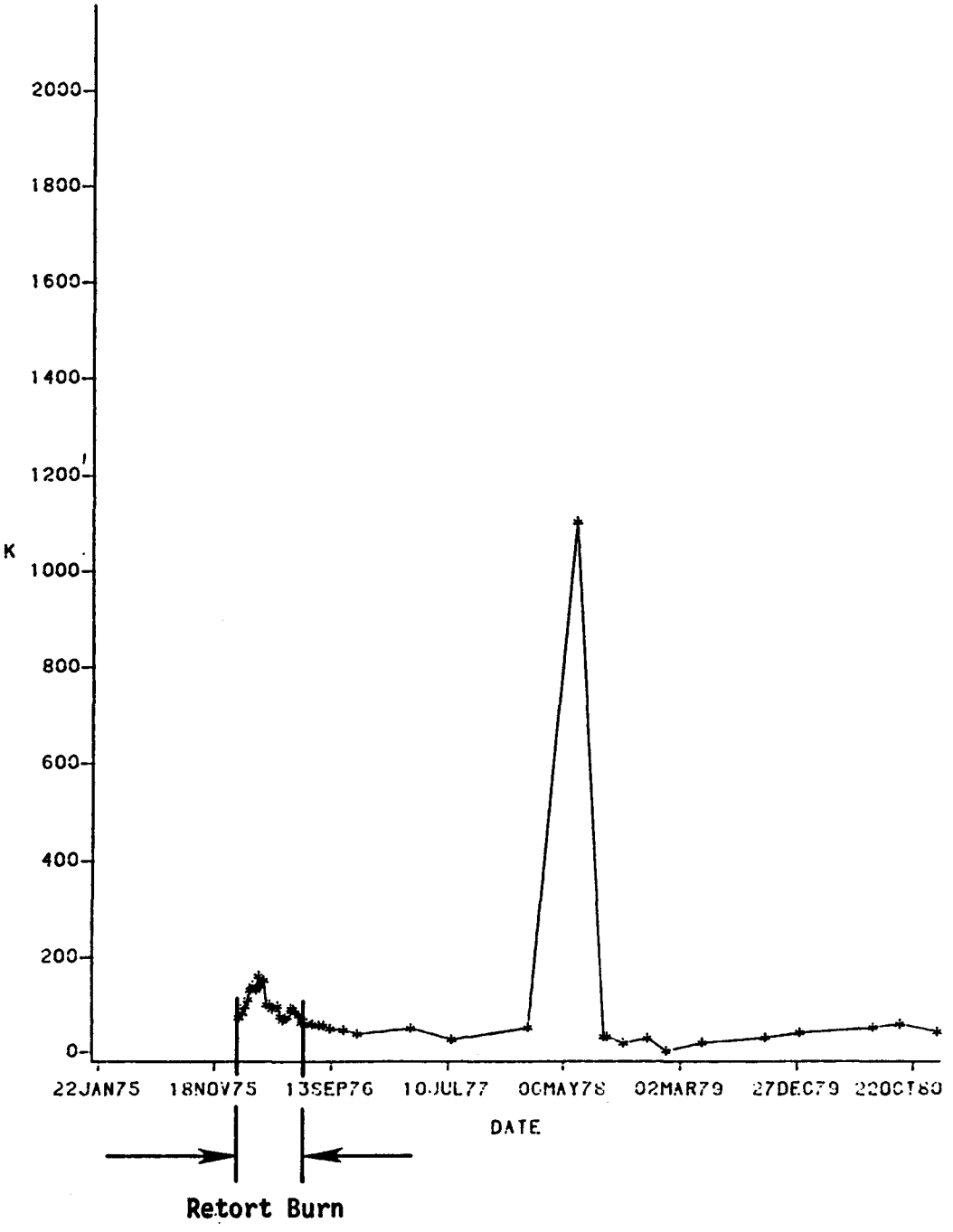
LOC	YR	MO	DY	S203 (MG/L)	HG (MG/L)	SE (MG/L)	S04 (MG/L)	CL (MG/L)	F (MG/L)	SI (MG/L)	N03 (MG/L)	NA (MG/L)	K (MG/L)	AS (MG/L)
LWR001	80	1	3	9.20	-.020	-.020	2400.00	50.00	5.90	5.0	42.00	570.0	260.00	.050
		4	30				430.00	62.00	1.10		50.00			
		9	18			-.010	1500.00	20.00	8.30		33.00	280.0	140.00	-.020
LWR002	80	1	3	32.00	-.020	-.020	850.00	44.00	8.20	12.0	-.10	340.0	270.00	.050
		4	30			-.010	860.00	110.00	8.20		24.00	310.0	290.00	-.020
LWR004	80	1	2	40.00	-.020	-.020	330.00	100.00	21.00	26.0	40.00	960.0	41.00	-.020
		7	10			.020	710.00	320.00	18.00		780.00	1100.0	52.00	.040
		9	18			.020	580.00	350.00	19.00		1200.00	1000.0	59.00	.050
		12	22			.020	970.00	260.00	23.00	25.0	470.00	1200.0	43.00	.090
		3	26		.001	.010	240.00	300.00	23.00		150.00	1100.00	61.00	.020
LWR005	80	1	2	108.00	-.020	-.020	190.00	64.00	38.00	35.0	100.00	1200.0	270.00	.020
		3	27		.006	-.005	310.00	330.00	30.00		200.00	1200.0	250.00	.060
		7	10			.010	340.00	240.00	24.00		540.00	1000.0	260.00	.090
		9	18			-.010	270.00	240.00	33.00		580.00	1000.0	250.00	.090
		12	22			-.010	310.00	240.00	29.00	35.0	220.00	1000.0	260.00	.060
LWR006	80	1	2	104.00	-.020	-.020	260.00	75.00	17.00	28.0	130.00	1000.0	42.00	.020
		3	26											
					.001	-.010	310.00	490.00	21.00		240.00	1300.0	84.00	.020
		7	10			.020	470.00	350.00	18.00		640.00	1100.0	73.00	.060
		9	18			.020	320.00	420.00	28.00		1100.00	1600.0	55.00	.030
		12	22			.020	690.00	520.00	21.00	21.0	400.00	1100.0	56.00	.040

LOGAN WASH
WATER QUALITY PARAMETERS
RETORTS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	TOT ALK (MG/L CACO3)	HCO3 (MG/L CACO3)	CO3 (MG/L CACO3)	TDS (MG/L)	TOT. SUSP. SOLID (MG/L)	PB (MG/L)	NI (MG/L)	PHEN (MG/L)	CD (MG/L)	DOC (MG/L)	OIL AND GREASE (MG/L)
LWR001	80	1	3	310.0	310.0	-1.0	3900.0	47.0	.020	.030	.480	-.020	27.00	33.00
		4	30	280.0	280.0	-1.0	1000.0	40.0			.002			2.00
		9	18	370.0	370.0	-1.0	2800.0	10.0	.020	.030	.050	-.010		11.00
LWR002	80	1	3	200.0	-1.0	120.0	1600.0	4.0	-.020	.020	.084	-.020	16.00	18.00
		4	30	210.0	10.0	200.0	1600.0	51.0	.020	-.020	.060	-.010		9.00
LWR004	80	1	2	2100.0	780.0	1300.0	2600.0	4.0	.020	-.020	13.000	-.020	184.00	19.00
		7	10	2600.0	1500.0	1100.0	3300.0	-1.0	.020	-.020	.900	-.010		15.00
		9	18	2800.0	670.0	2100.0	3100.0	31.0	.020	-.020	.005	-.010		13.00
		12	22	2600.0	1300.0	1300.0	3700.0	160.0	.050	.020	3.000	-.010	270.00	32.00
		3	26	2800.00	1000.0	1800.0	3100.0	12.0	-.020	.040	7.000	-.001	260.00	10.00
LWR005	80	1	2	3500.0	1100.0	2400.0	4000.0	6.0	-.020	.030	15.000	-.020	445.00	18.00
		3	27	3200.0	1400.0	1800.0	3800.0	6.0	-.020	.050	13.000	-.010	390.00	25.00
		7	10	2800.0	1600.0	1200.0	3400.0	-1.0	.020	-.020	12.000	-.010		8.00
		9	18	2600.0	1400.0	1200.0	3400.0	24.0	.020	-.020	.003	-.010		3.00
		12	22	2500.0	1400.0	1100.0	3300.0	5.0	.020	.060	2.500	-.010	300.00	6.00
LWR006	80	1	2	4100.0	1500.0	2600.0	3000.0	16.0	.020	.030	22.000	-.020	310.00	27.00
		3	26	4700.0	1700.0	3000.0	3700.0	24.0	-.020	.030	9.000	-.010	340.00	12.00
		7	10	5500.0	1800.0	3700.0	3500.0	8.0	.020	-.020	13.000	-.010		11.00
		9	18	9100.0	4300.0	4800.0	4100.0	21.0	-.020	.020	.020	-.010		8.00
		12	22	4200.0	1000.0	3200.0	3500.0	34.0	.040	.050	6.200	-.010	410.00	10.00

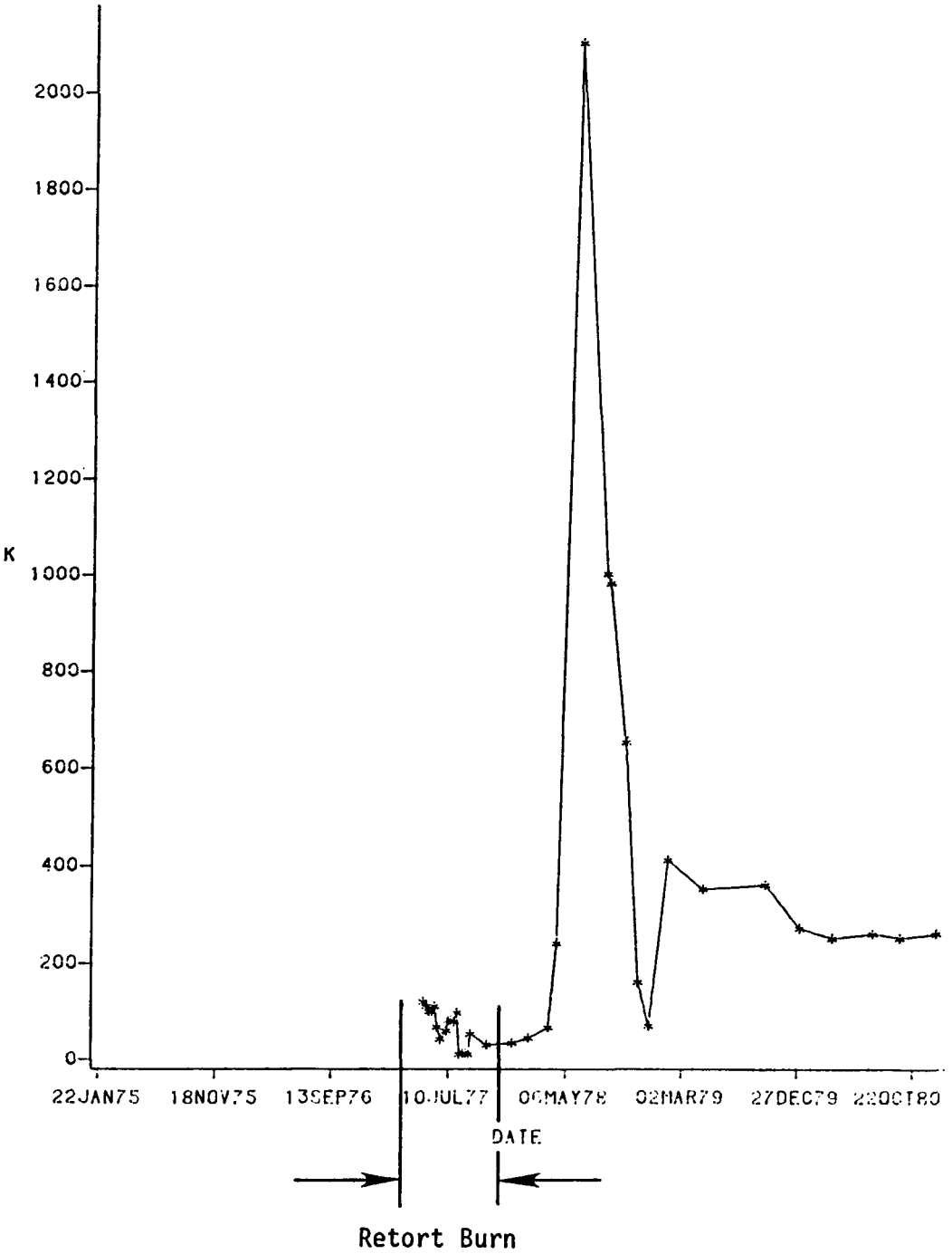
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR004



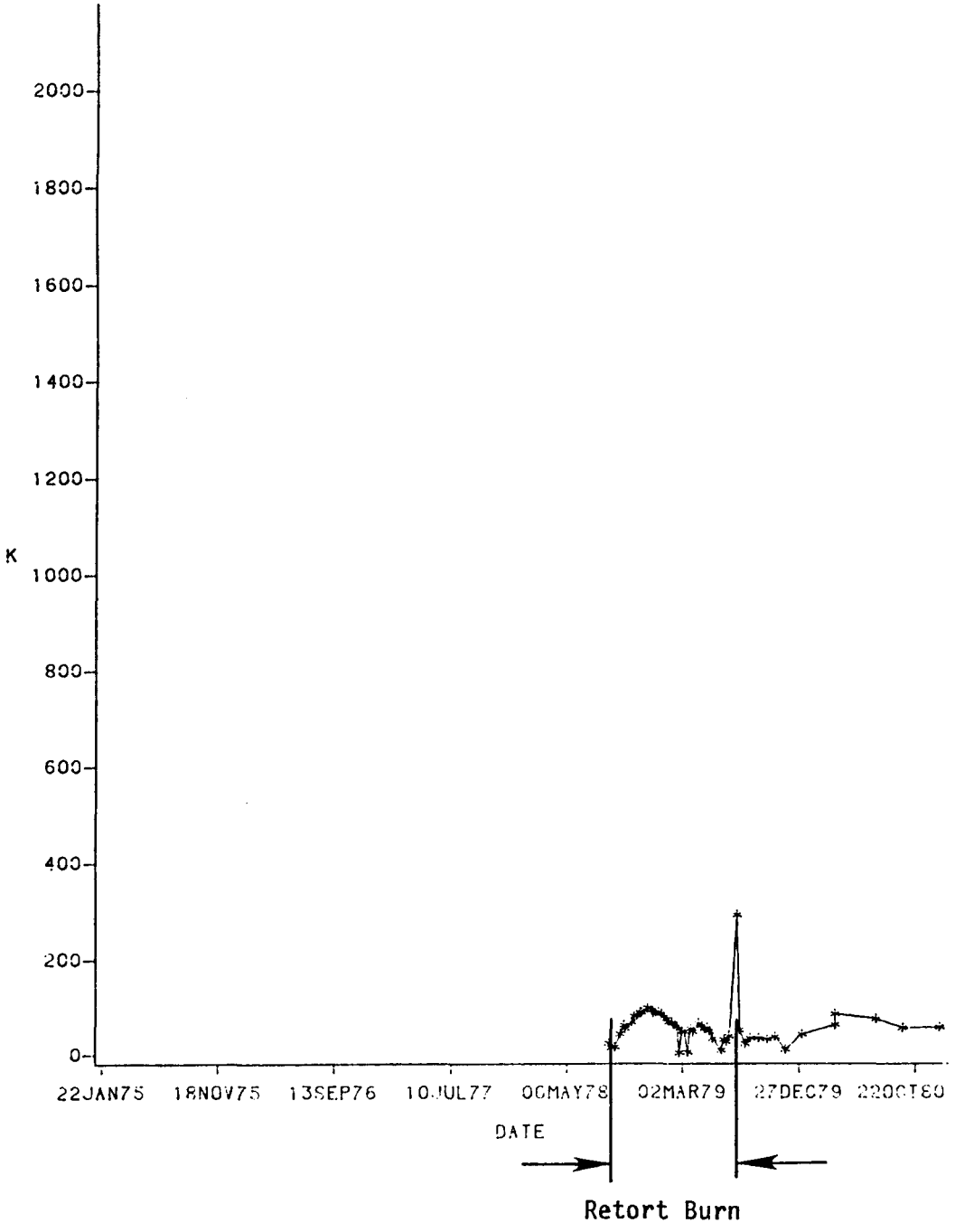
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR005



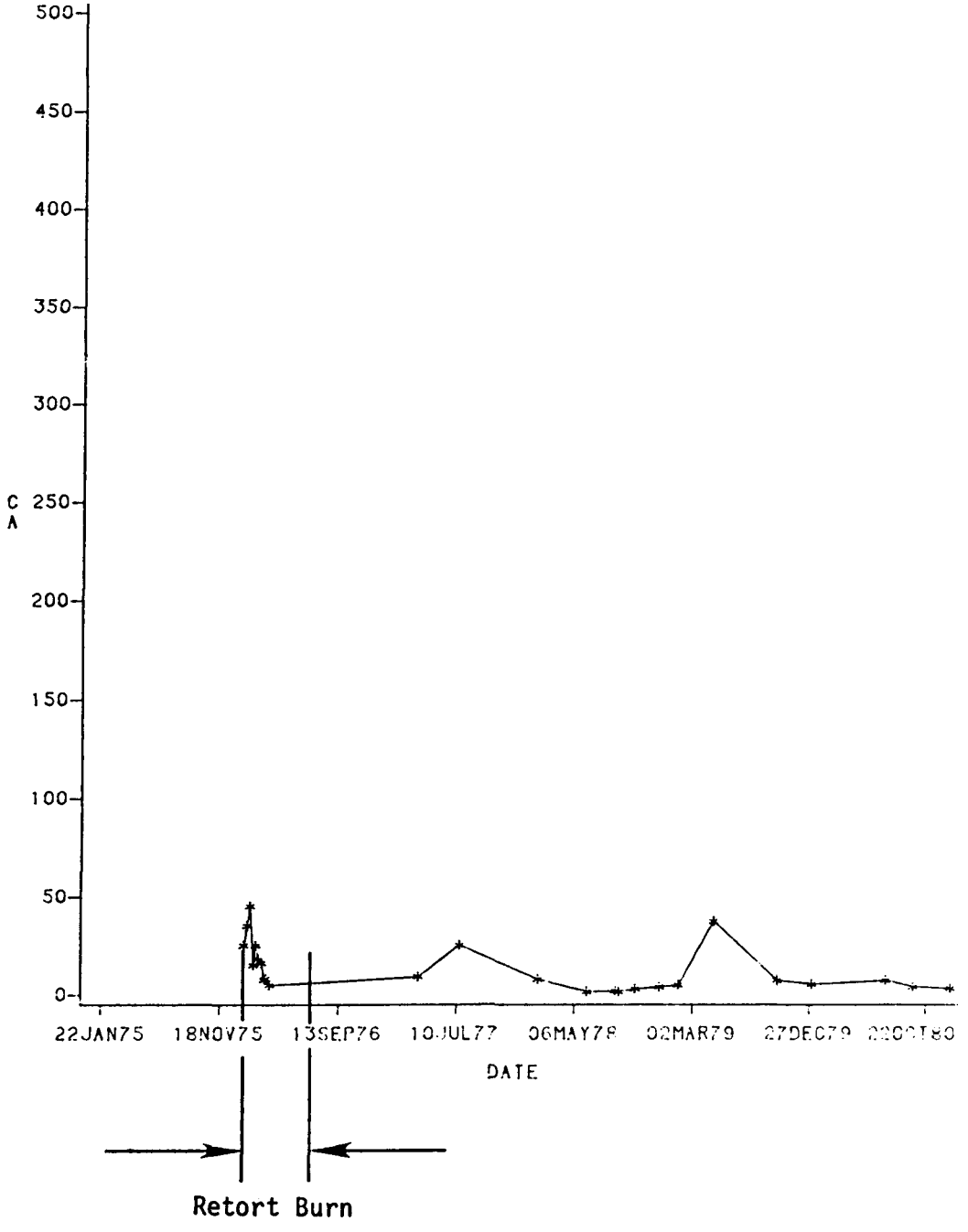
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR006



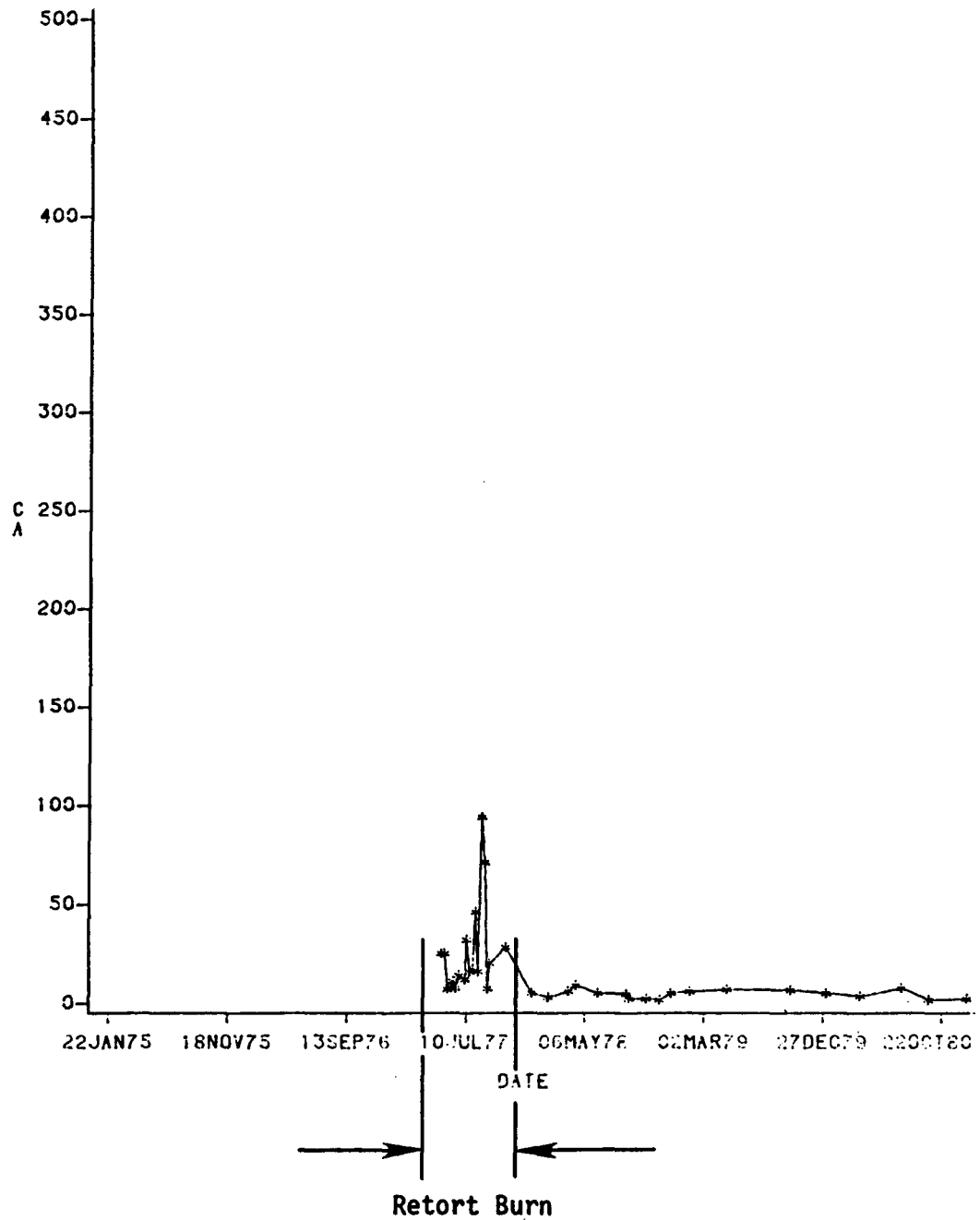
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR004



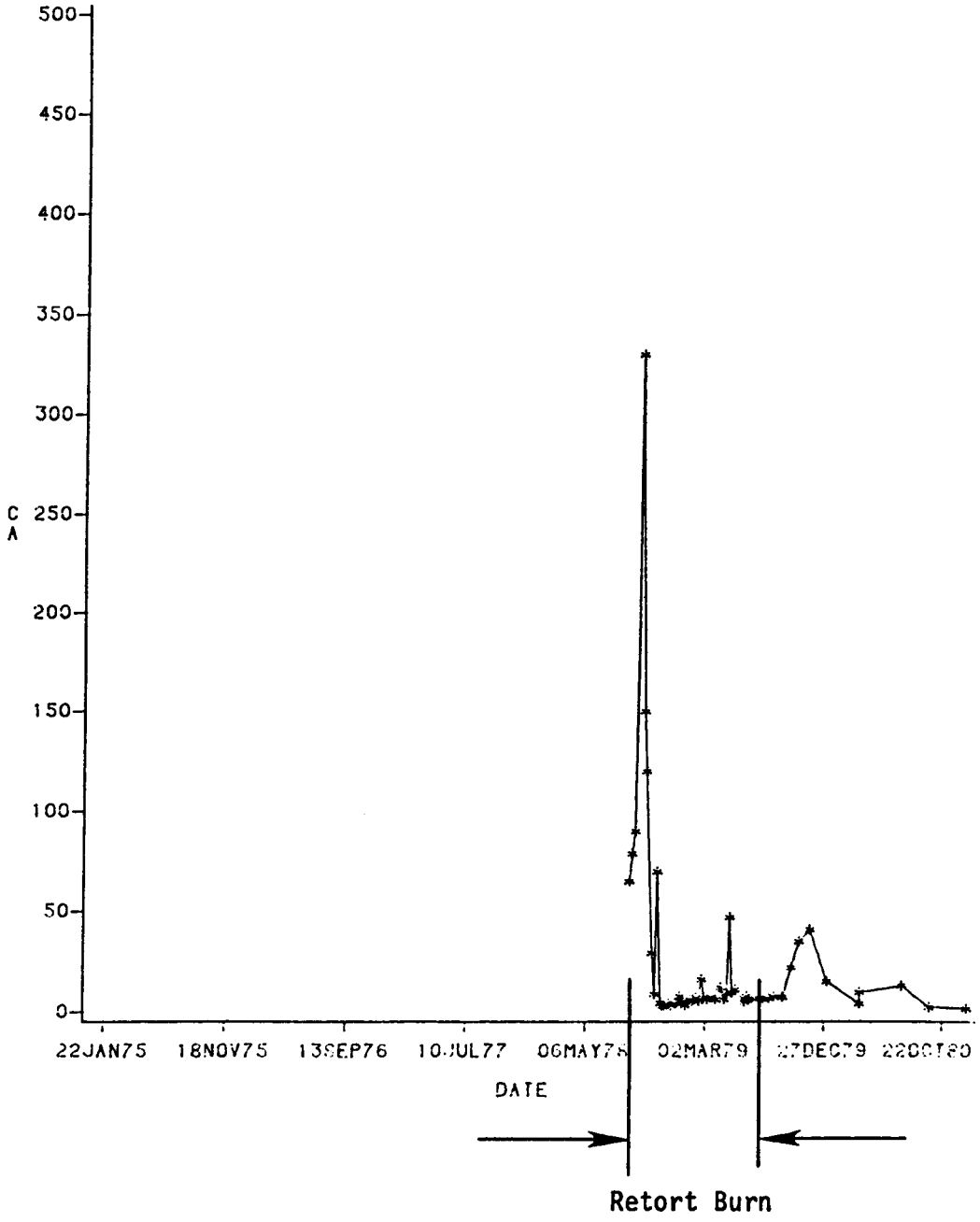
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

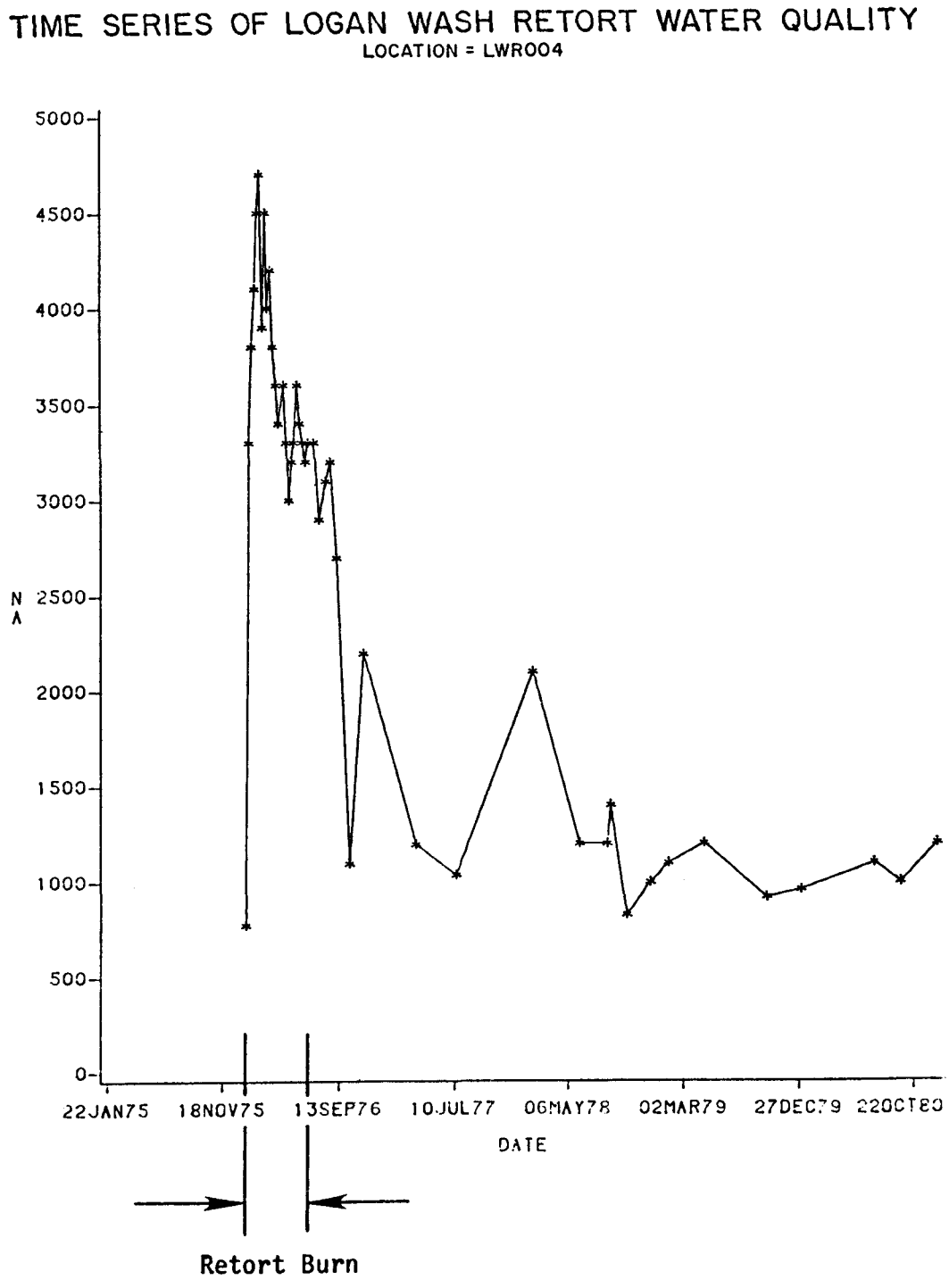
LOCATION = LWR005



TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

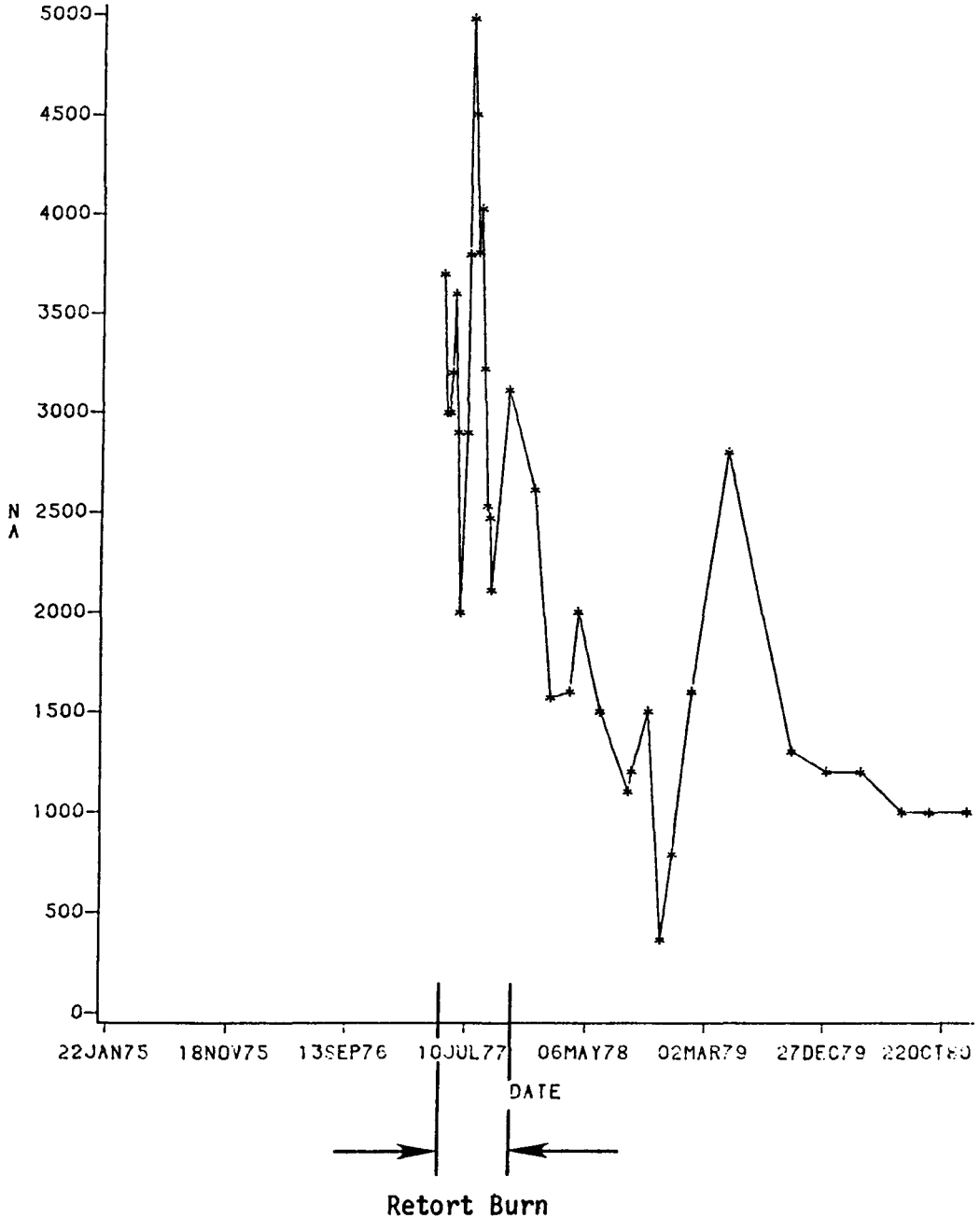
LOCATION = LWR006




TIME SERIES OF LOGAN WASH RETORT WATER QUALITY
LOCATION = LWR004
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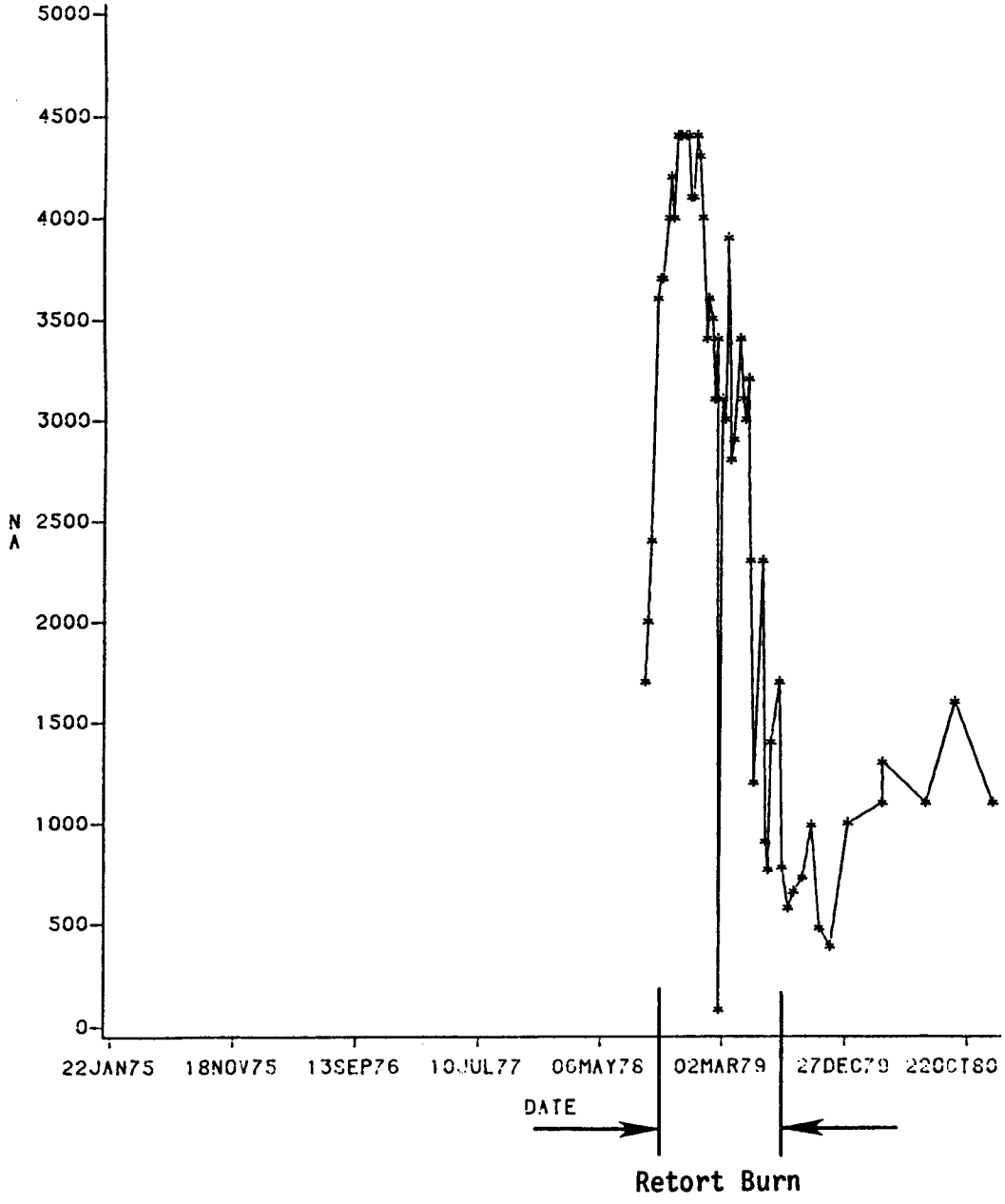
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

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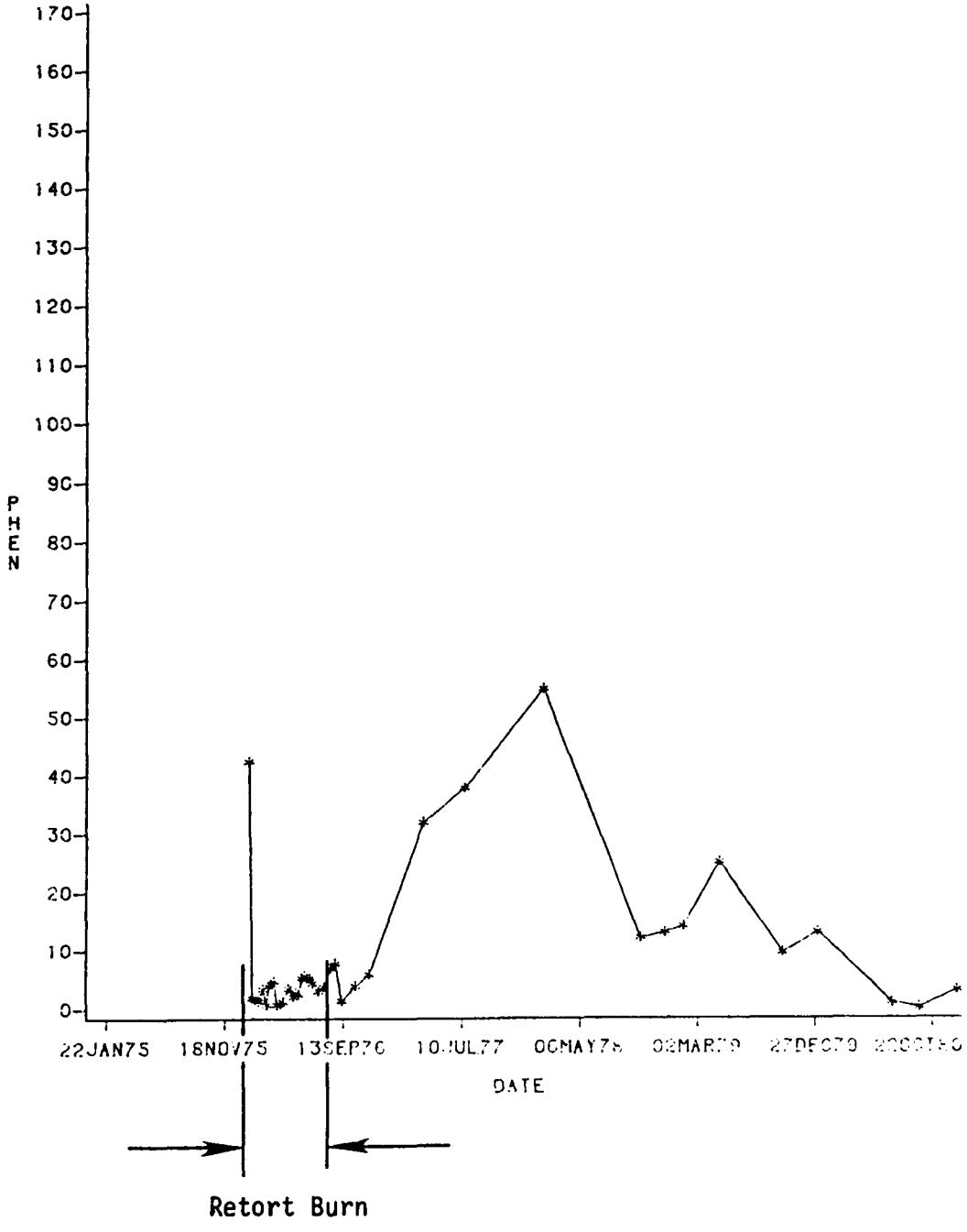
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR006



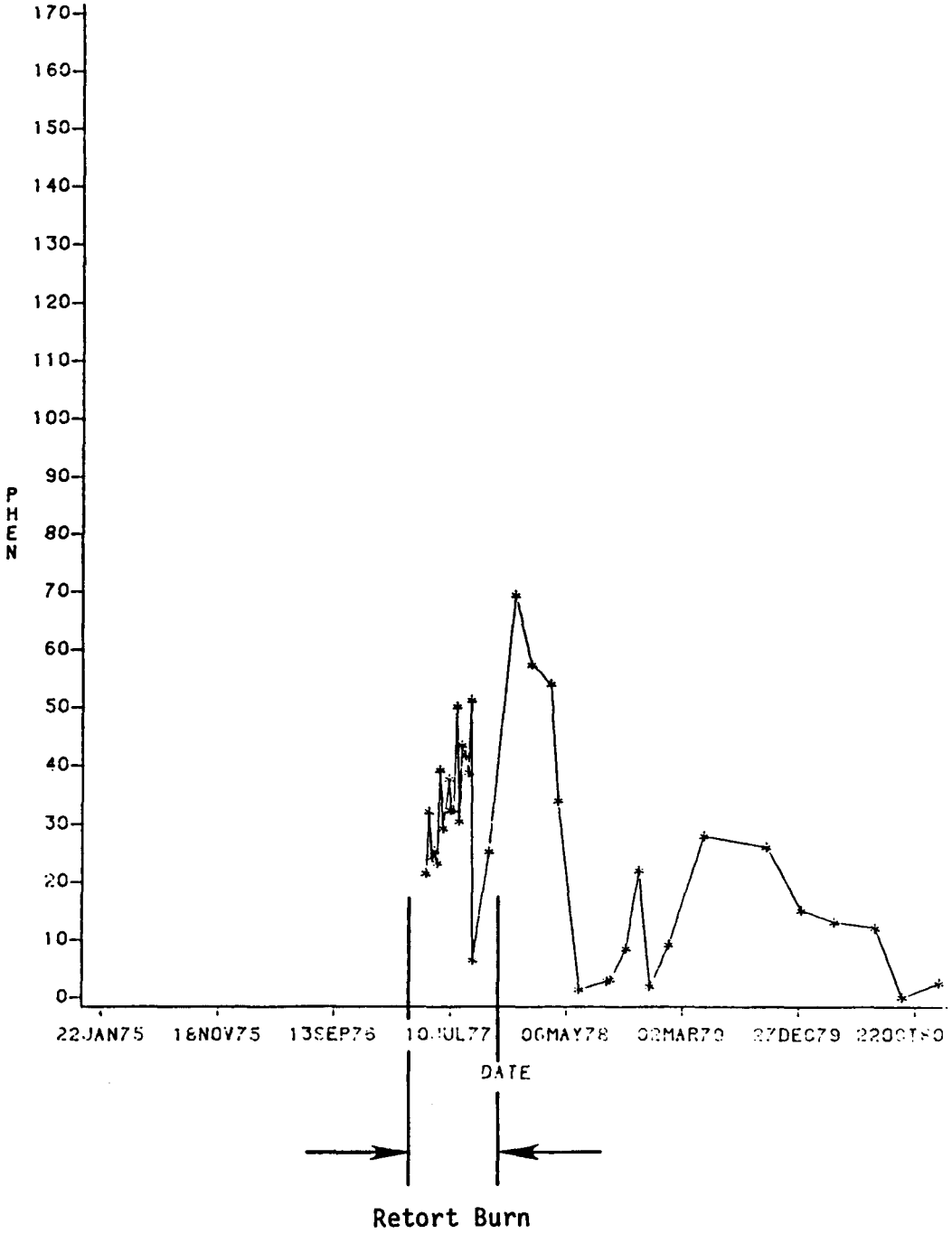
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR004



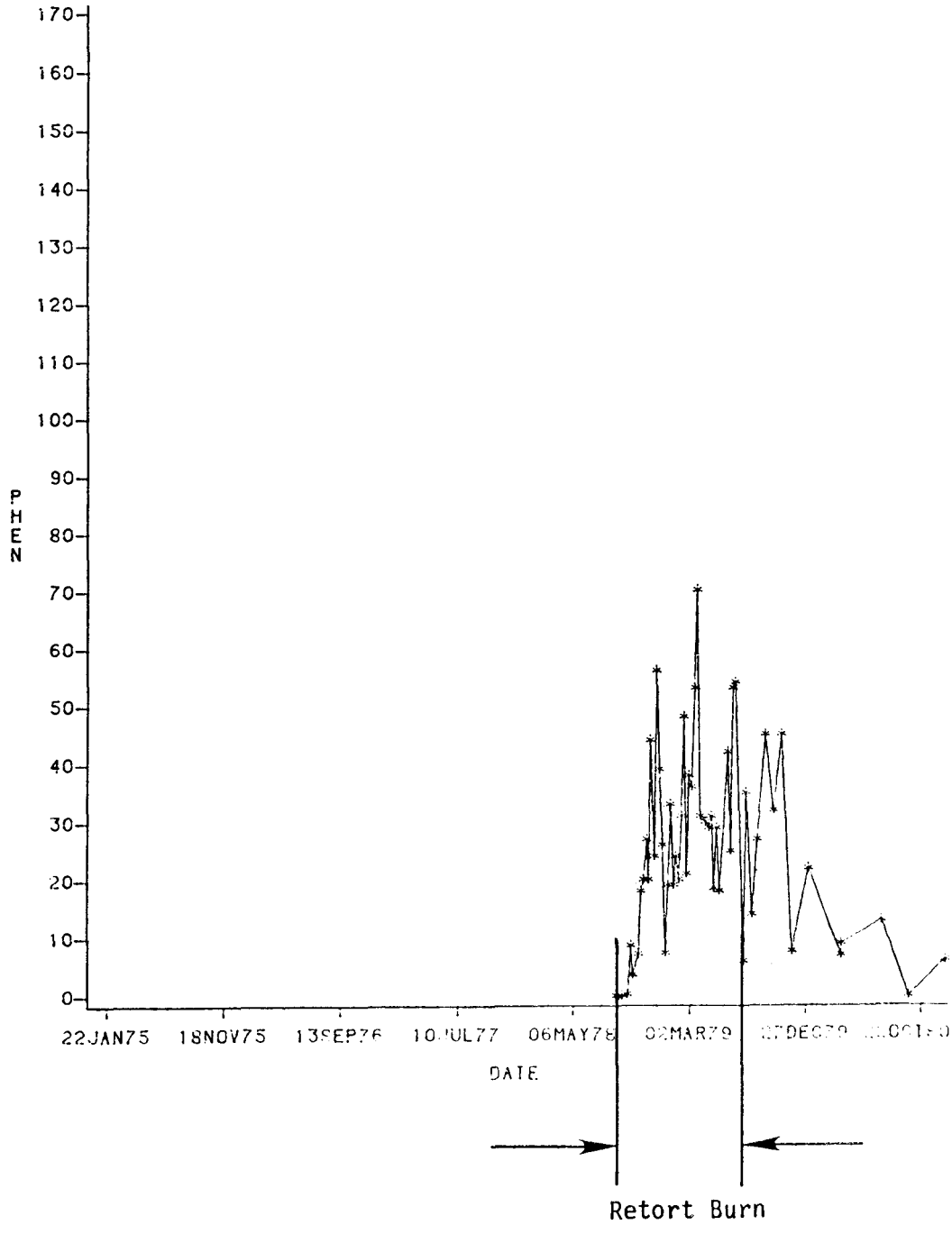
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR005



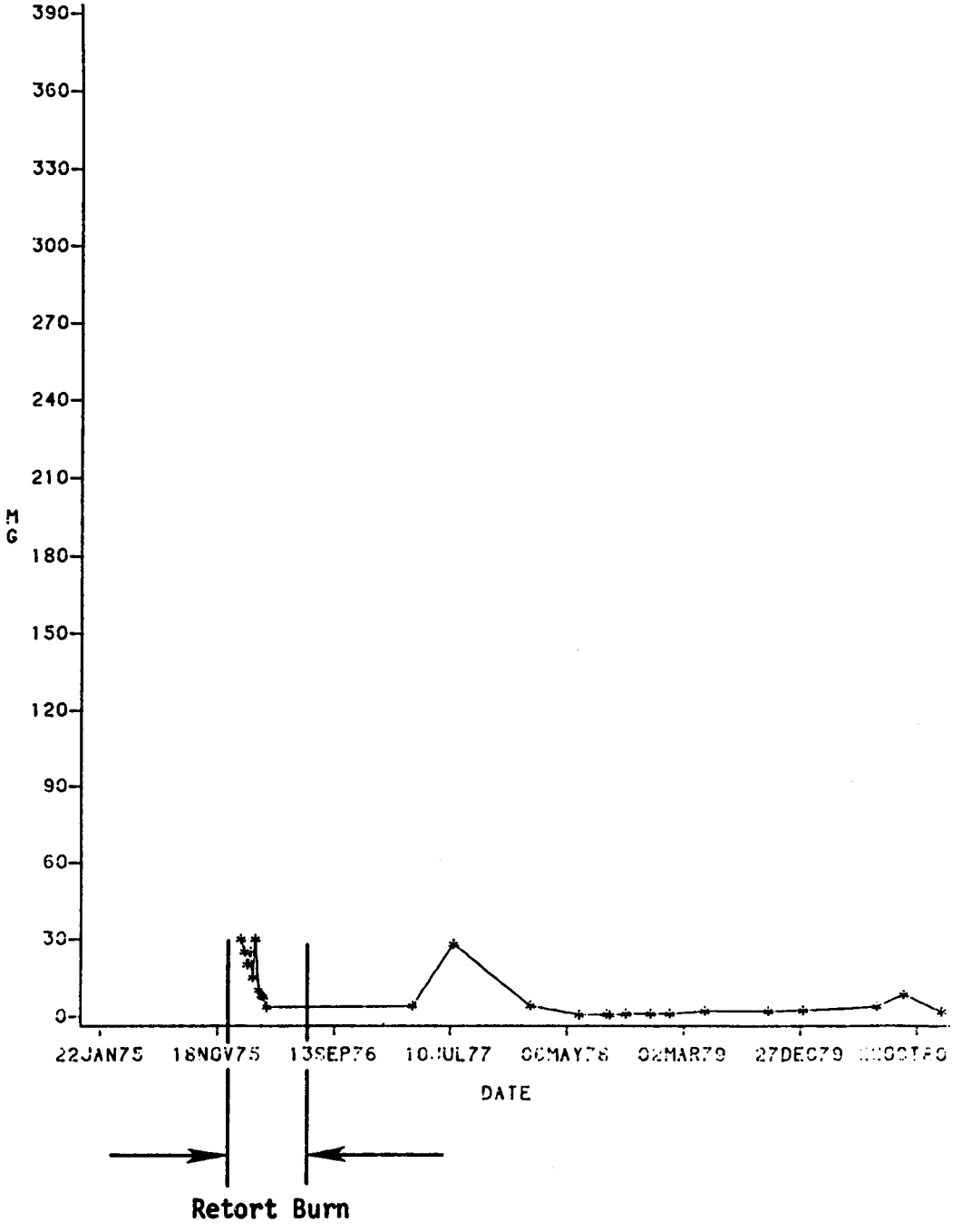
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR006



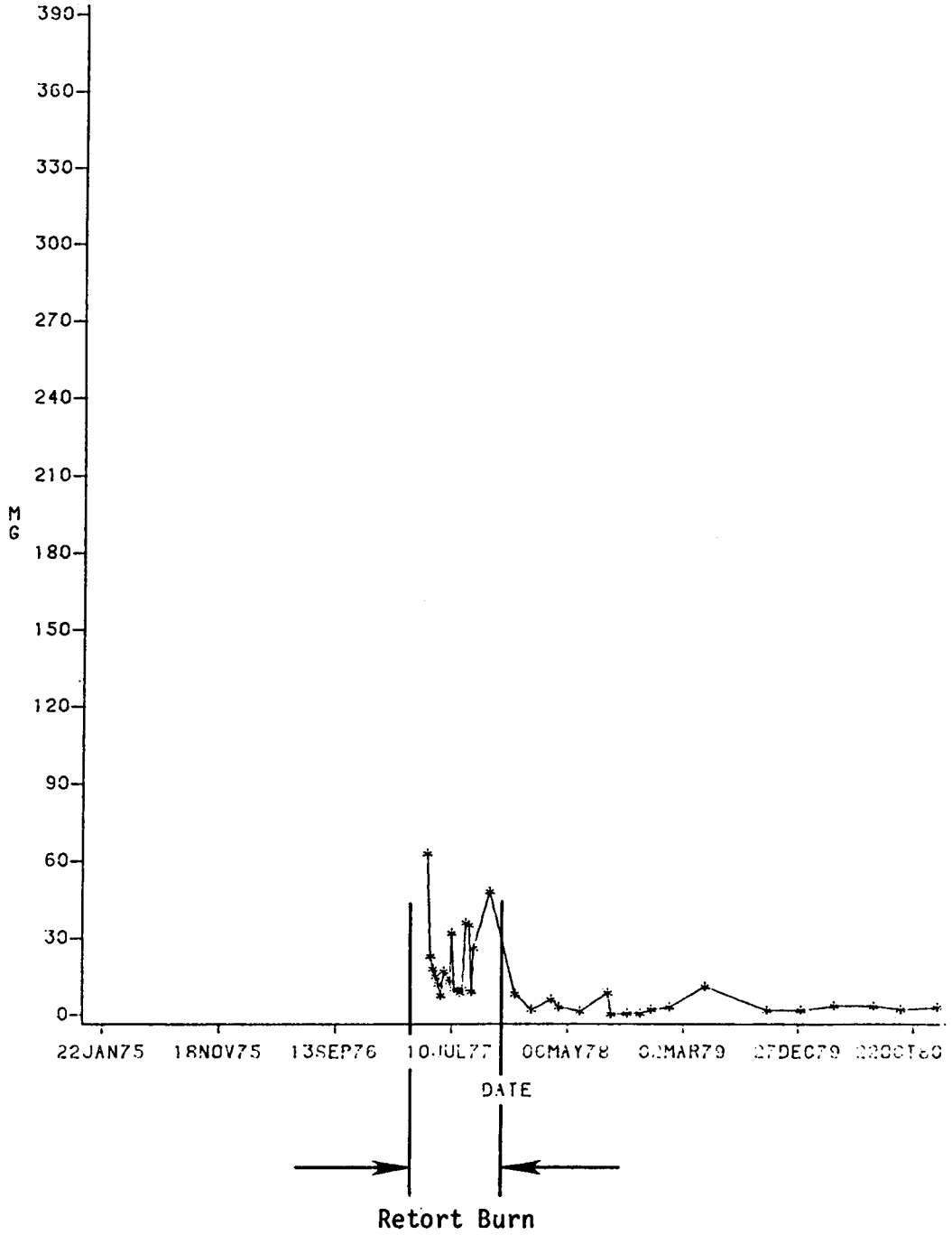
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR004



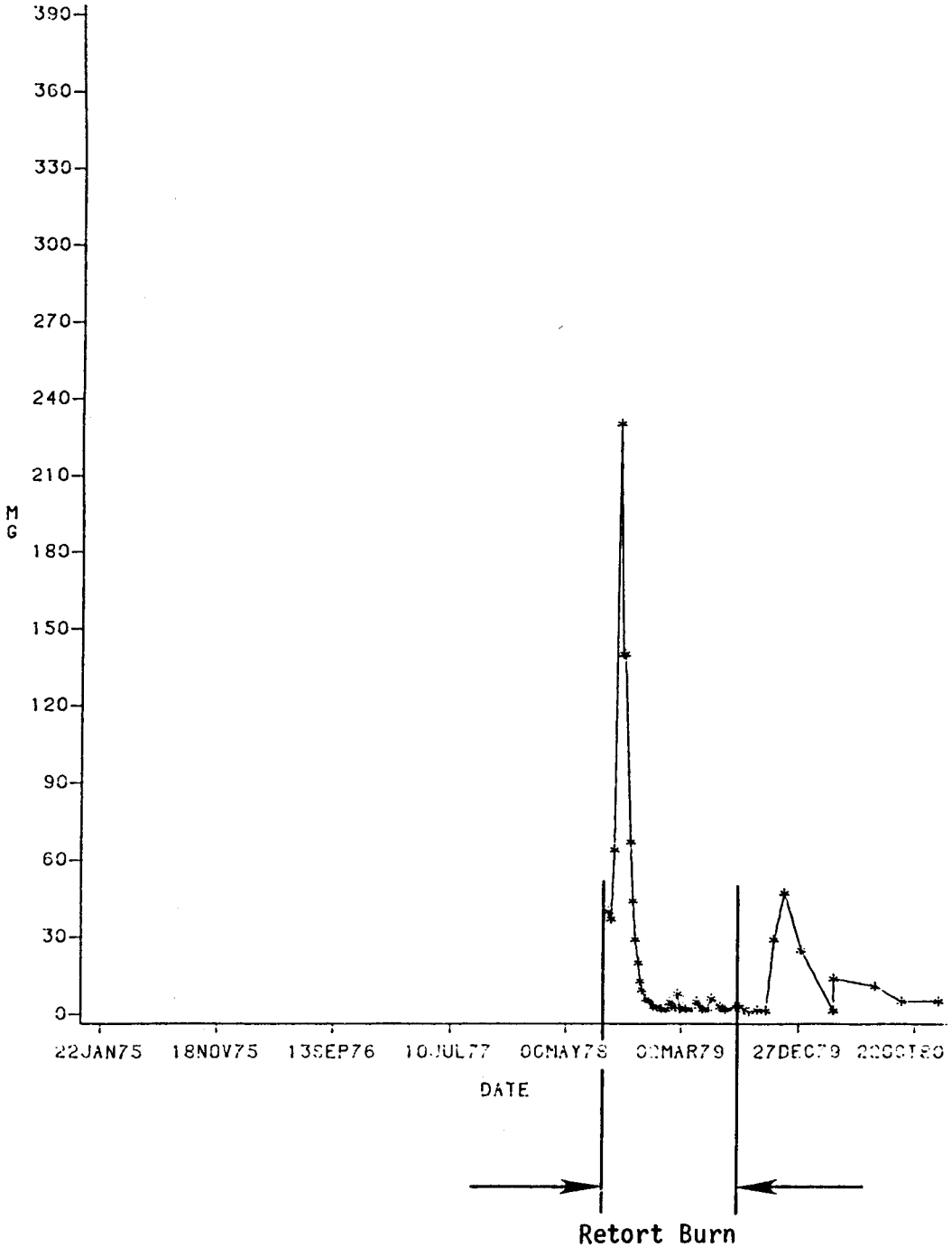
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR005



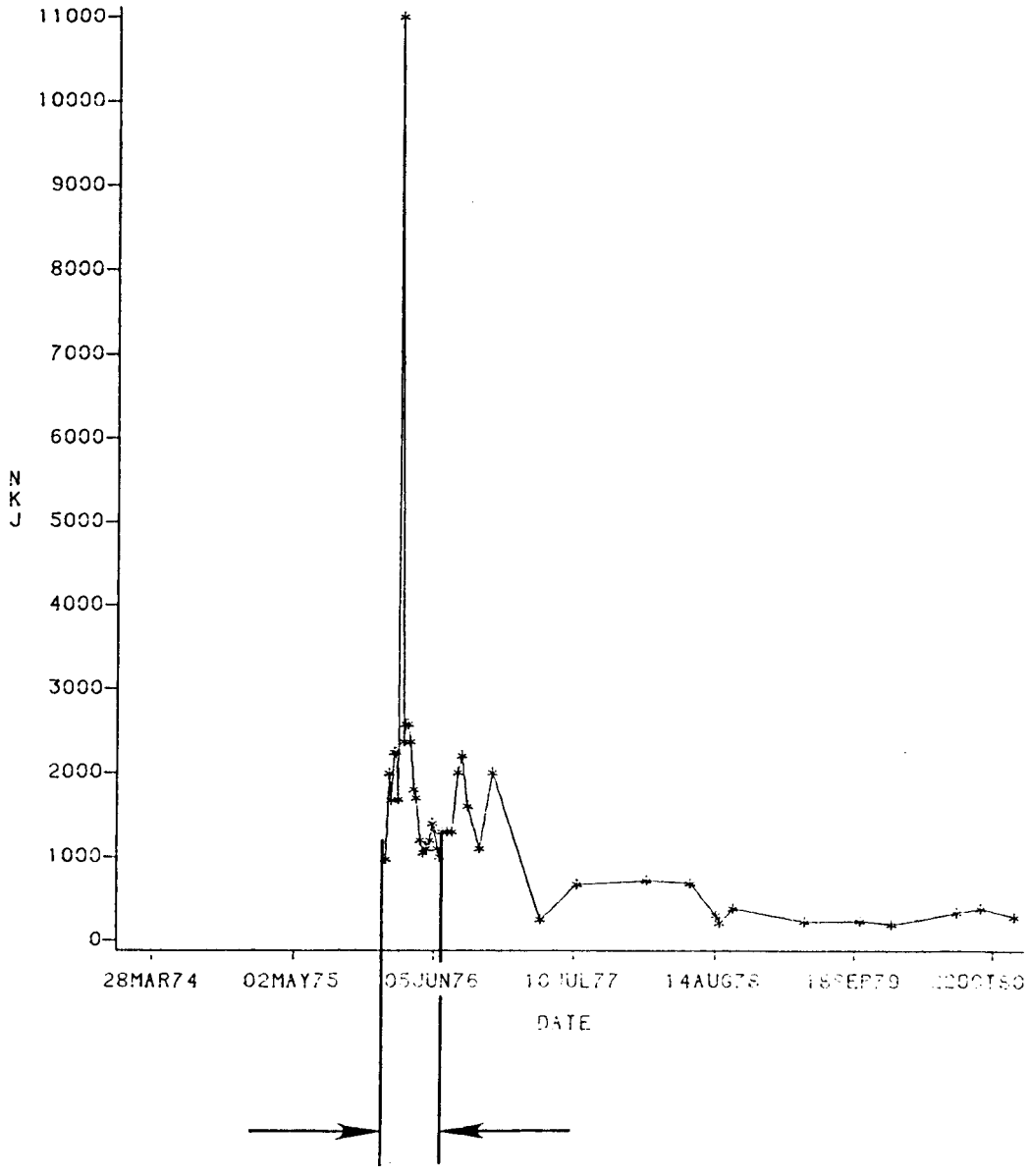
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR006



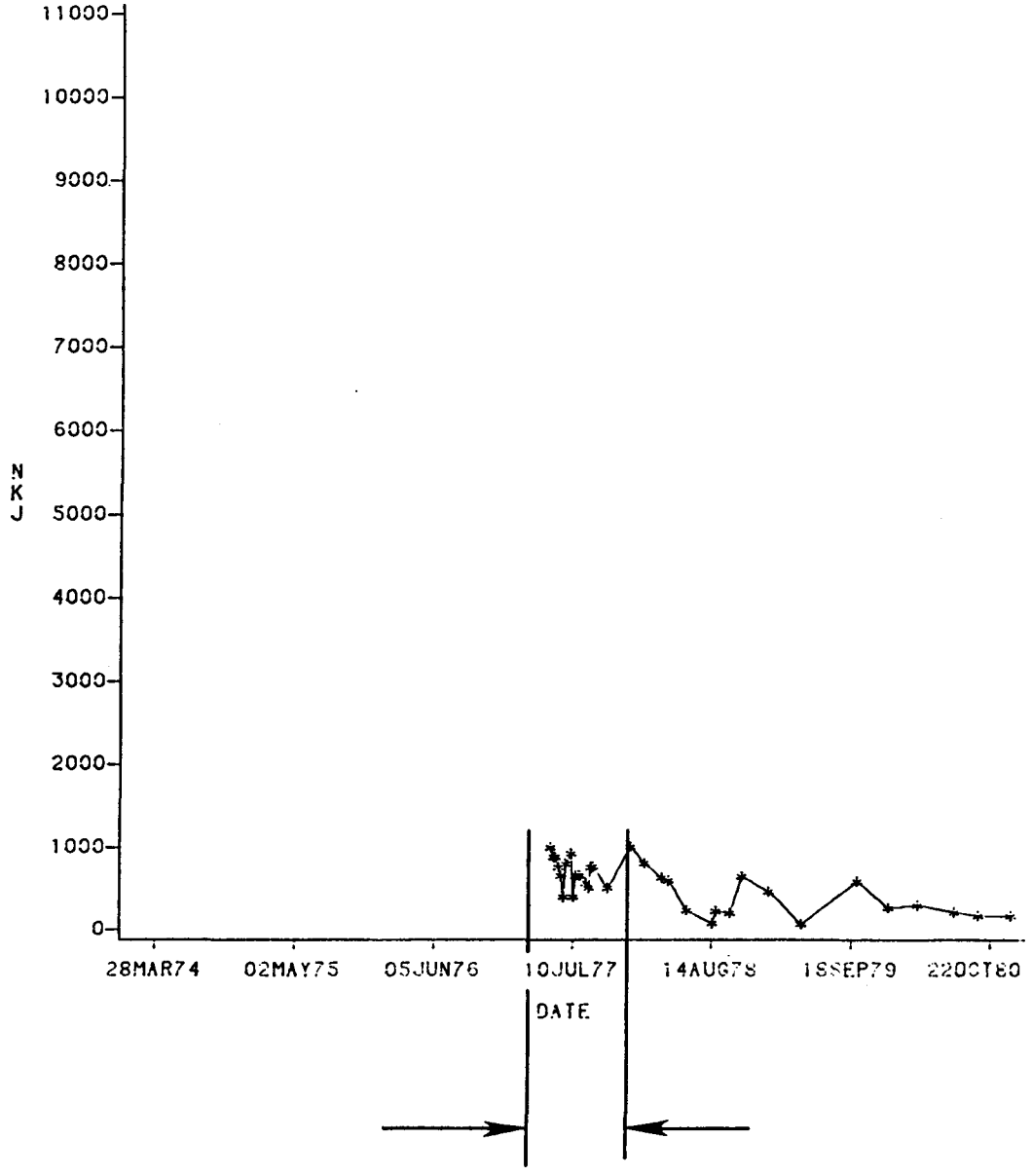
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR004



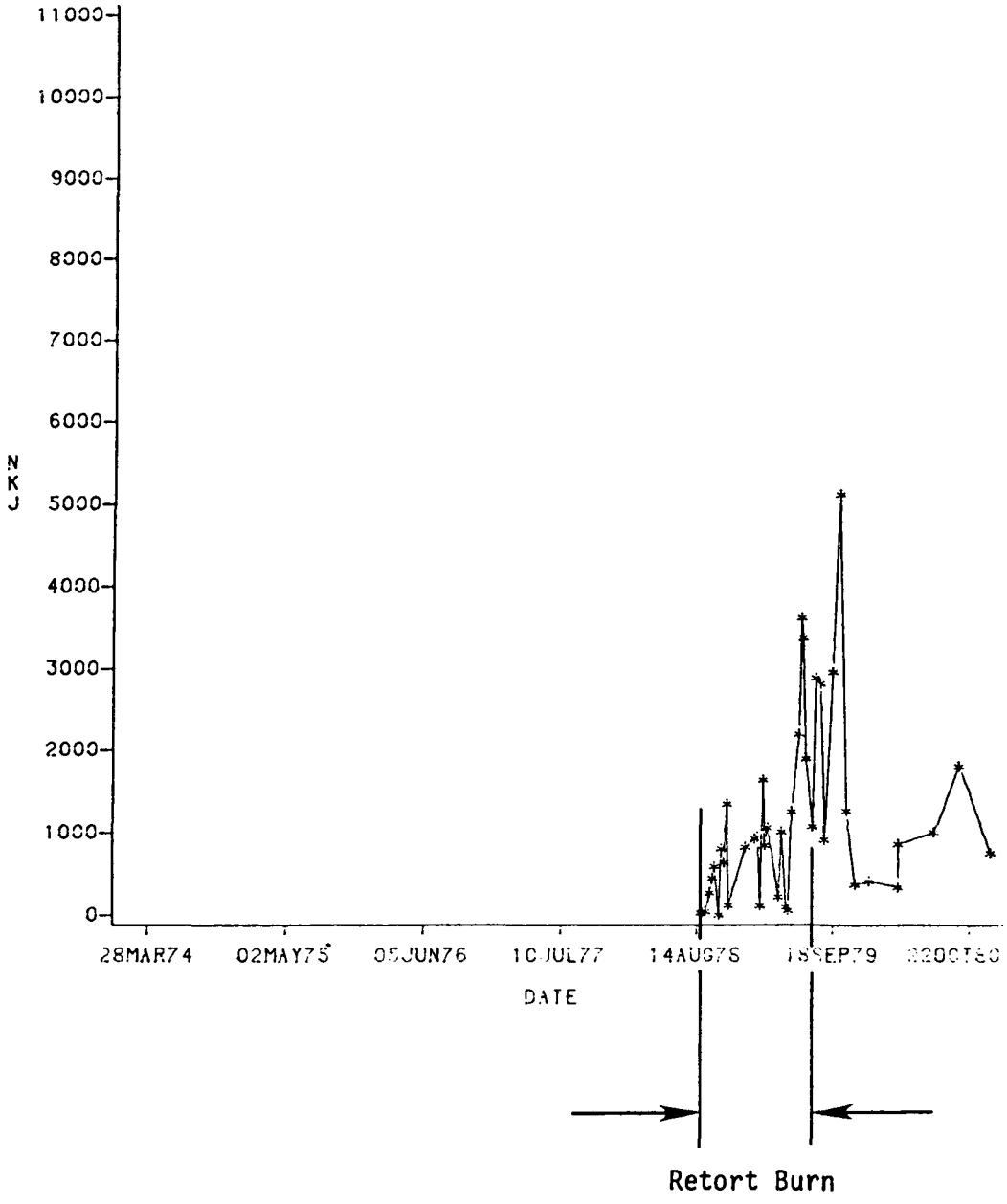
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR005



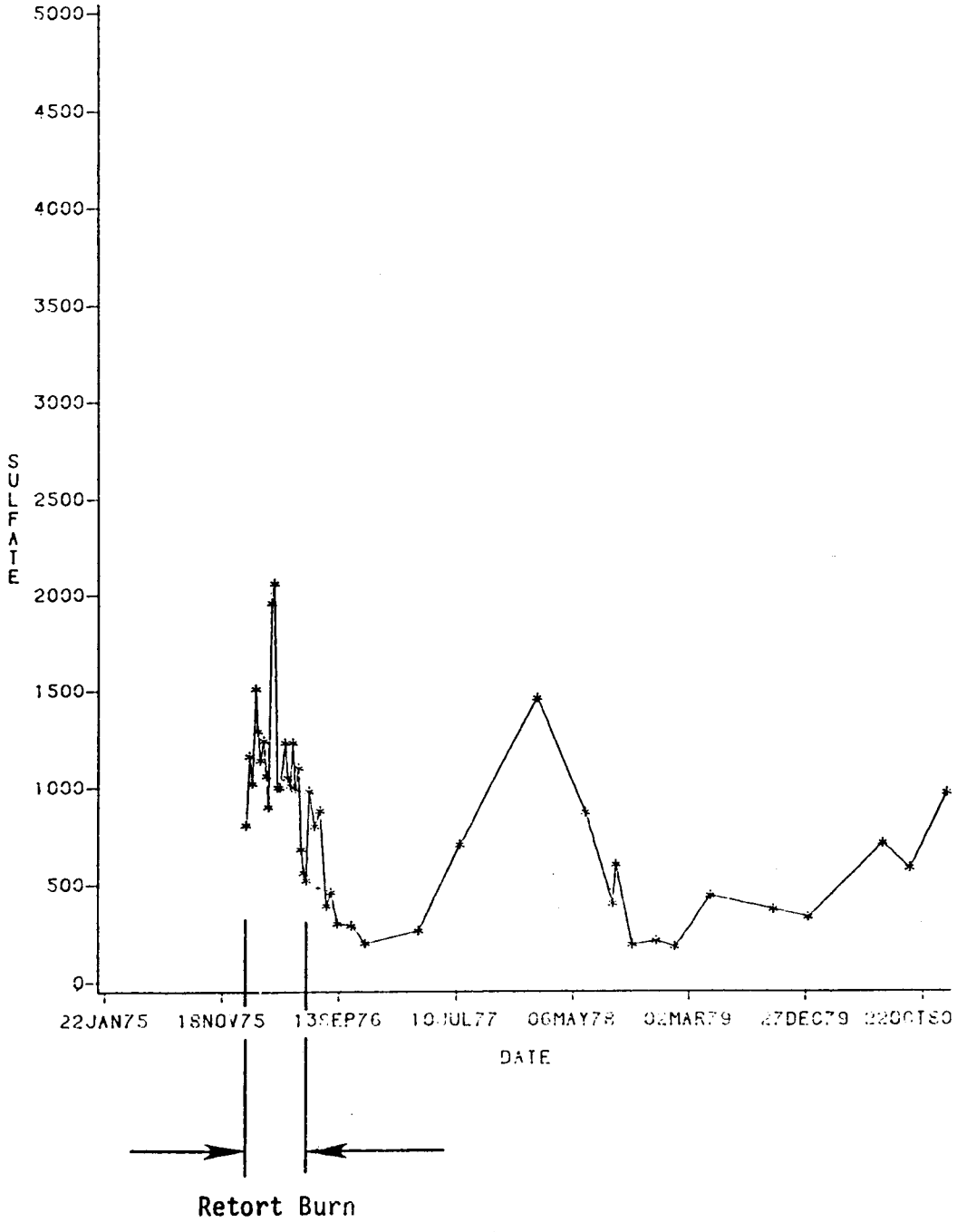
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR006



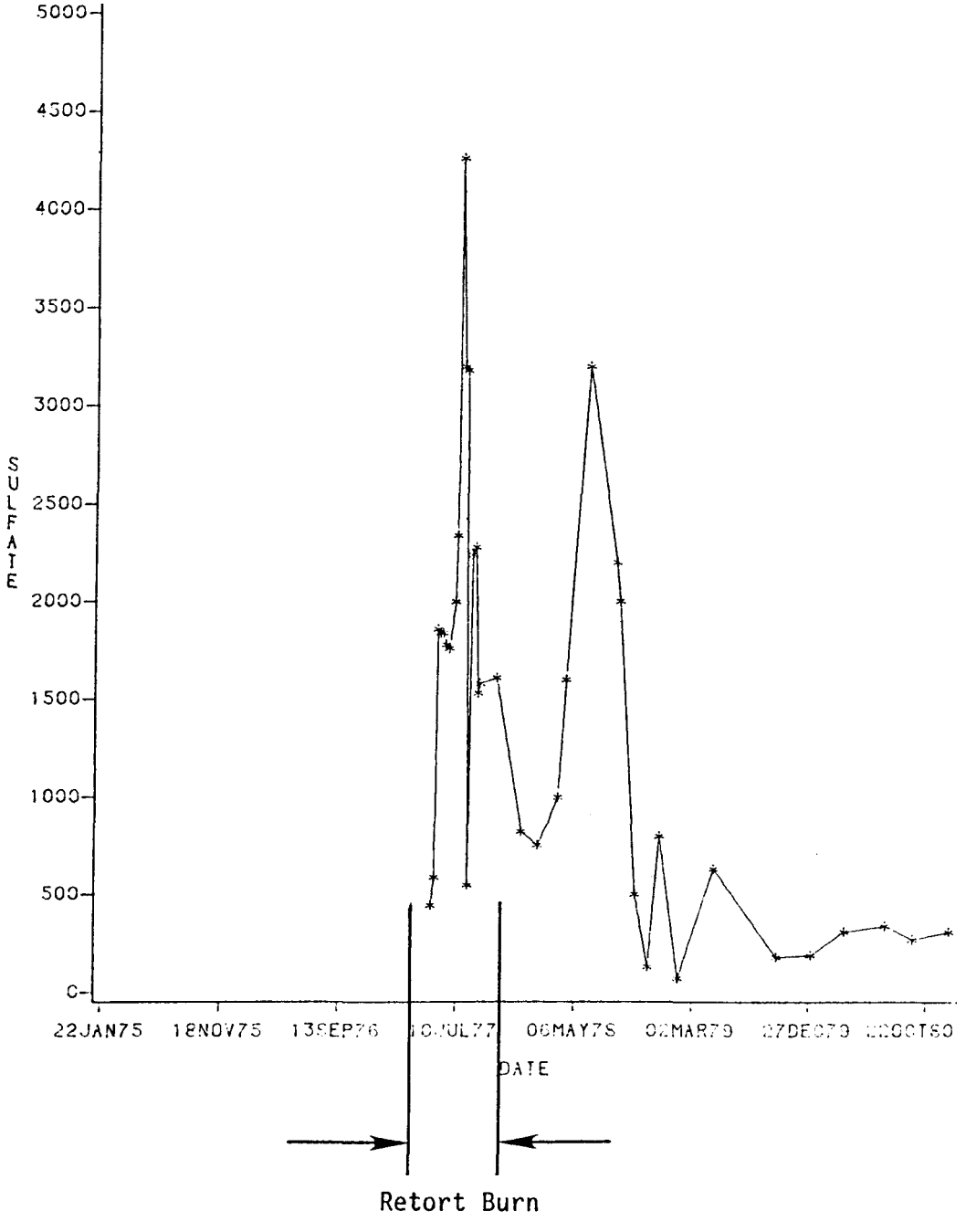
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR004



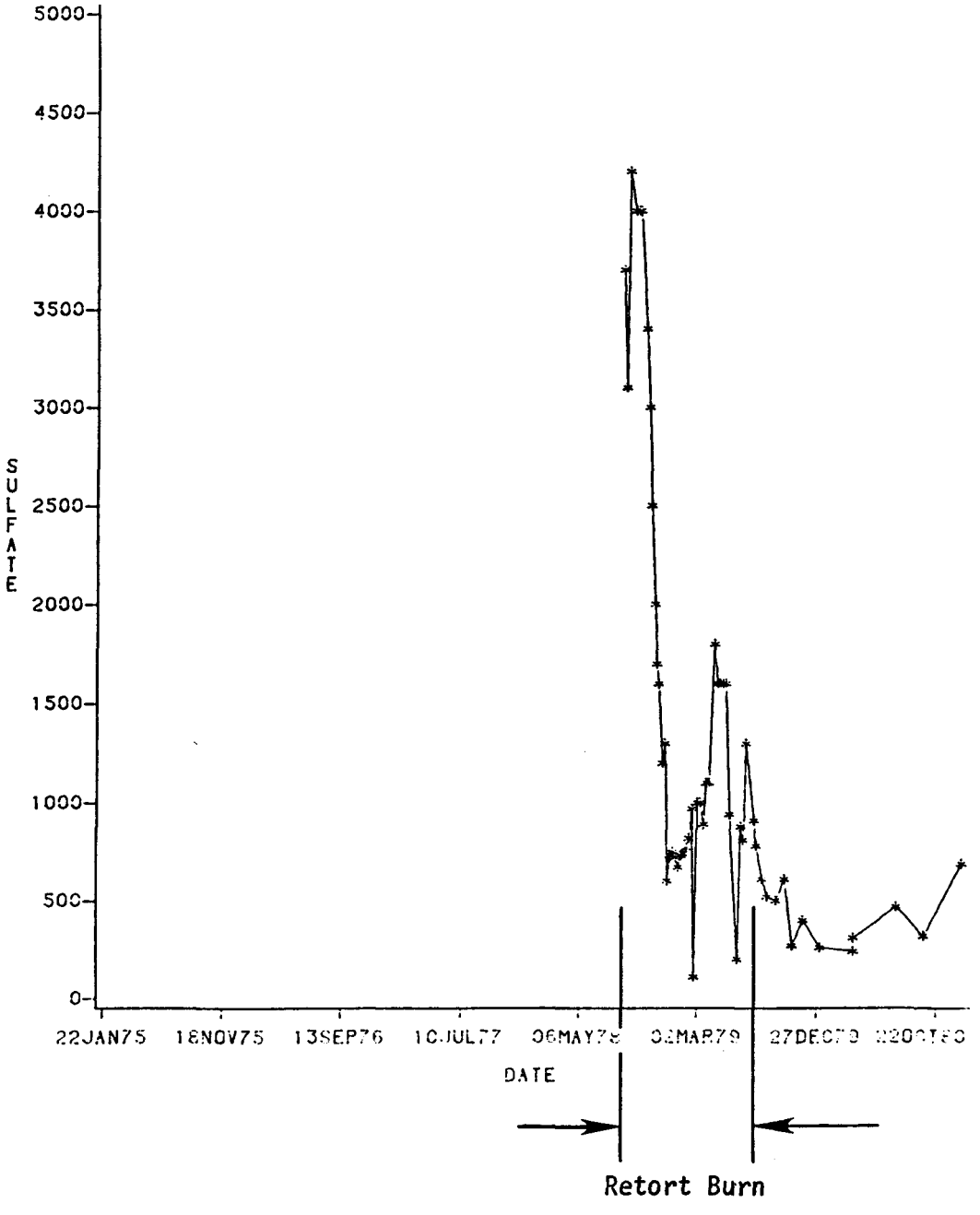
TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR005



TIME SERIES OF LOGAN WASH RETORT WATER QUALITY

LOCATION = LWR006



LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	CA (MG/L)	B (MG/L)	CU (MG/L)	V (MG/L)	MO (MG/L)	LI (MG/L)	ZN (MG/L)	AL (MG/L)	BA (MG/L)	SR (MG/L)	AMMONIA AS N (MG/L)
LWD601	81	4	30						.400					4.10
LWD602	80	1	10	2.9	.200	-.020	-.050	.020	.200	-.020	-.100	-.500	.30	.06
			22	2.9	.100	-.020	-.050	.020	.200	-.020	-.100	-.500	.20	.05
		2	26	4.9	.400	-.020	-.050	.010	.200	.040	.100	-.500	.20	-.04
		4	2	5.5	.500	-.020	-.050	.100	.200	.030	-.100	-.500	.40	-.04
		5	1	52.0	.200	.040	-.050	.010	.200	.030	-.100	-.500	-.10	-.04
		7	17	6.0	.300	-.020	-.050	.020	.200	-.010	-.100	-.500	-.50	.10
		8	13	2.3	.300	-.020	-.050	.010	.200	-.020	-.100	-.500	.90	-.04
		9	8	2.9	.400	-.020	-.050	.020	.200	-.020	-.100	-.500	-.50	.10
		10	15	1.3	.200	-.020	-.050	.020	.200	-.020	-.100	-.500	-.50	-.04
		11	13	1.9	.300	-.020	-.050	.030	.200	-.020	-.100	-.500	-.50	-.04
		12	16	2.7	.300	-.020	-.050	-.010	.200	-.020	-.100	-.500	-.50	-.04
	81	2	12	2.0	.300	.020	-.050	.010	.200	-.020	-.100	-.500	-.50	-.04
		3	11	2.1	.400	.030	-.050	.030	.200	-.020	-.100	-.500	-.50	.08
LWD603	80	1	22	12.0	3.900	-.020	-.050	.010	1.200	-.020	.100	.500	1.70	3.10
		2	26	16.0	4.200	-.020	-.050	.010	1.200	.020	.200	-.500	1.50	4.00
		3	20	18.0	4.400									3.20
		4	2	15.0	4.400	-.020	-.050	.100	1.300	.030	-.100	-.500	1.20	12.00
			16	19.0	.400									3.80
		5	1	71.0	4.700	.020	-.050	.040	1.400	.030	-.100	-.500	2.80	3.00
		6	26	17.0	4.100									4.10
		7	17	27.0	3.900	.020	-.050	.020	1.200	.010	-.100	-.500	2.80	3.90
		8	13	19.0	4.300	-.020	-.050	.010	1.600	-.020	-.100	-.500	2.10	3.00
		9	8	23.0	4.400	-.020	-.050	.030	1.100	-.020	-.100	-.500	1.20	3.90
		10	15	20.0	4.800	-.020	-.050	.010	1.300	-.020	-.100	-.500	2.20	3.30
		11	24	17.0	4.500									7.50
		12	16	15.0	4.800	-.020	-.050	1.000	1.100	-.020	-.100	-.500	1.00	.30
	81	3	11	13.0	4.800	.020	-.050	.030	1.000	-.020	-.100	-.500	.90	2.10
LWD604	80	1	22	42.0	17.000	-.020	-.050	2.000	.800	-.020	-.100	1.000	13.00	12.00
		2	26	42.0	13.000	.020	.050	1.500	.900	.040	.100	.500	12.00	12.00
		3	20	32.0	9.100									13.00
		4	2	32.0	11.000	-.020	-.050	1.700	1.000	.040	-.100	-.500	5.90	12.00
			16	59.0	12.000									1.60
		5	1	80.0	9.800	.030	-.050	1.700	.800	.030	-.100	1.200	10.00	11.00
			15											
		6	26	31.0	7.300									8.90
		7	17	37.0	7.400	.020	-.050	1.000	.700	-.010	-.100	-.500	11.00	7.00
			30	30.0	6.600									7.80
		8	13	28.0	7.000	-.020	-.050	.700	.800	-.020	-.100	-.500	6.50	6.00
			26	36.0	6.200									6.10
		9	8	38.0	6.100	-.020	-.050	.500	.700	.030	-.100	-.500	5.70	5.30

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	CA (MG/L)	B (MG/L)	CU (MG/L)	V (MG/L)	MO (MG/L)	LI (MG/L)	ZN (MG/L)	AL (MG/L)	BA (MG/L)	SR (MG/L)	AMMONIA AS N (MG/L)
														6.00
LWD604	80	9	18	37.0	6.300									
		10	15	46.0	6.500	.030	-.050	.080	.800	.020	-.100	-.500	12.00	6.30
			30	47.0	5.000	-.020	-.050	.090	.600	.040	-.100	-.500	5.80	5.20
		11	13	45.0	4.900	-.020	-.050	.100	.600	.020	-.100	-.500	6.00	2.50
			24	49.0	4.700									13.00
		12	16	50.0	4.500	-.020	-.050	5.900	.500	-.020	-.100	-.500	5.90	3.50
			23											
	81	1	14	67.0	5.400	.020	-.050	.500	.600	-.020	-.100	-.500	5.80	3.50
		2	12	48.0	5.800	-.020	-.050	.200	.800	-.020	-.100	-.500	5.90	.05
		3	11	60.0	4.900	-.020	-.050	.500	.600	-.020	-.100	-.500	6.30	2.40
LWD605	80	1	30	9.5	35.000	-.020	-.050	.080	2.300	.030	-.100	1.000	6.50	1900.00
		2	26	18.0	37.000	-.020	-.050	-.010	2.100	.060	.100	1.200	5.00	25.00
		3	20	14.0	47.000									280.00
		4	2	13.0	56.000	-.020	-.050	.100	1.900	.030	-.100	1.000	3.00	230.00
			16	14.0	46.000									270.00
		5	1	62.0	47.000	.020	-.050	-.010	1.600	.030	-.100	1.300	4.70	240.00
		6	26	8.2	69.000									200.00
		7	17	15.0	69.000	-.020	-.050	.020	1.100	-.010	-.100	-.500	4.40	160.00
			30	6.9	71.000									170.00
		8	13	6.4	68.000	-.020	-.050	.030	1.300	-.020	-.100	-.500	2.50	50.00
			26	12.0	67.000									150.00
		9	8	10.0	64.000	-.020	-.050	.200	1.100	-.020	-.100	-.500	2.10	100.00
			18	5.3	66.000									100.00
		10	15	9.3	40.000	-.020	-.050	.300	1.200	-.020	-.100	-.500	3.00	50.00
			30	10.0	24.000	-.020	-.050	.040	1.100	.020	-.100	-.500	1.40	25.00
		11	13	8.3	28.000	-.020	-.050	.100	1.100	.020	-.100	-.500	1.80	39.00
			24	13.0	17.000									34.00
		12	16											8.80
			23	19.0	12.000	.020	-.050	.200	.900	-.020	-.100	-.500	2.10	11.00
	81	1	14	20.0	11.000	.040	-.050	.500	1.000	.020	-.100	-.500	1.90	8.10
		2	12	13.0	12.000	-.020	-.050	.200	1.100	-.020	-.100	-.500	1.50	18.00
		3	11	8.2	18.000	.050	-.050	.400	1.100	.020	-.100	-.500	1.40	48.00
LWD606	80	8	13	170.0	26.000	.020	-.050	3.100	1.700	.020	-.100	-.500	5.60	6.30
		9	8	800.0	27.000	.040	-.050	1.500	1.000	-.020	-.100	-.500	5.50	9.00
		10	15	210.0	29.000	.060	-.050	1.000	1.400	.030	-.100	-.500	10.00	3.60
		12	23	200.0	26.000	.080	-.050	.300	.900	.100	-.100	-.500	5.60	4.50
	81	1	14	220.0	28.000	.070	-.050	.800	1.100	.100	-.100	-.500	5.60	3.90
		2	12	180.0	27.000	.050	-.050	.600	1.200	.080	-.100	-.500	5.30	4.00
		3	11	190.0	26.000	.030	-.050	.600	1.000	.070	-.100	-.500	6.00	1.30
LWD607	80	1	3	3.0	.700	-.020	-.100	.300	.300	-.020	-.100	-.500	.40	1.50
			22	5.3	.900	-.020	-.050	.050	.300	-.020	.700	-.500	.40	1.00

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	CA (MG/L)	B (MG/L)	CU (MG/L)	V (MG/L)	MO (MG/L)	LI (MG/L)	ZN (MG/L)	AL (MG/L)	BA (MG/L)	SR (MG/L)	AMMONIA AS N (MG/L)
LWD607	80	8	13	27.0	14.000	-.020	-.050	2.700	.700	-.020	-.100	-.500	2.30	4.80
		12	23	9.2	5.300	.030	-.050	.200	.700	-.020	-.100	-.500	.60	4.20
	81	3	11	40.0	23.000	.020	-.050	.700	.700	.020	.100	-.050	2.40	15.00
LWD608	80	4	2	41.0	9.900	-.020	-.050	1.200	.400	.020	-.100	-.500	4.30	50.00
		9	18	67.0	5.800	.020	-.050	1.200	.600	-.020	-.100	-.500	3.00	9.60
		12	22	100.0	12.000	.020	-.050	.500	.500	-.020	-.100	-.500	3.60	10.00
	81	1	14	62.0	11.000	.020	-.050	1.400	.500	-.020	-.100	-.500	2.80	19.00
LWD610	80	2	5		40.000									
			26	35.0	40.000	-.020	-.050	.300	.400	.050	.100	1.600	.80	3.50
		3	20	11.0	40.000									.05
		4	2	8.2	43.000	-.020	-.050	.200	.600	.060	-.100	.500	1.10	1.40
			16	11.0	39.000									3.30
		5	1	61.0	48.000	.040	-.050	.100	.500	.070	-.100	1.800	.30	4.00
			15	8.7	37.000									-.04
		6	12	11.0	46.000	.090	-.050	.500	.600	.070	.100	-.500	-.50	5.80
		7	17	14.0	41.000	.030	-.050	.500	.500	.020	-.100	-.500	.50	4.60
		8	13	4.8	45.000	-.020	-.050	.200	.600	.030	-.100	-.500	1.20	4.60
		9	8	6.8	50.000	-.020	-.050	.400	.600	-.020	-.100	-.500	-.50	3.00
		10	15	5.3	51.000	.030	-.050	.400	.800	.030	-.100	-.500	.50	9.20
		11	13	4.3	47.000	.020	-.050	.600	.600	.030	-.100	-.500	1.00	4.20
		12	16	7.5	50.000	.020	-.050	.300	.600	.020	.100	-.500	-.50	4.50
	81	2	12	3.7	50.000	.030	-.050	.300	.600	.030	-.100	-.500	-.50	4.70
		3	11	4.4	50.000	.030	-.050	.300	.500	.030	-.100	-.500	.60	3.60
LWD611	80	2	5											
			26	17.0	39.000	-.020	-.050	.200	.500	.070	-.100	1.000	.40	6.00
		6	12	13.0	26.000	.200	-.050	1.700	.700	.060	-.100	-.500	.40	2.10
		7	17	16.0	28.000	.030	-.050	1.000	.600	.020	-.100	-.500	.50	3.70
				16.0	28.000	.030	-.050	1.000	.600	.020	-.100	-.500	.50	3.70
		11	13	5.3	37.000	.030	-.050	.700	.600	.040	-.100	-.500	.90	3.00
		12	16	6.9	41.000	.030	-.050	.400	.600	.020	-.100	-.500	-.50	4.90
	81	2	12	3.4	43.000	.040	-.050	.600	.700	.030	-.100	-.500	-.50	1.20
		3	11	4.6	44.000	.040	-.050	.800	.500	.050	.200	-.500	.80	4.80

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	FECAL COLIF COLONY /100 ML	TOTAL COLIF COLONY /100 ML	SO3 (MG/L)	N KJELD. (MG/L)	FE (MG/L)	MG (MG/L)	AG (MG/L)	TOC (MG/L)	ALPHA (PCI/1)	BETA (PCI/1)	RADIUM 226 (PCI/1)
LWD601	81	4	30											
LWD602	80	1	10	-1.0	-1.00		-1.00	.400	.9	-.010	11.0		23.00	.82
			22					.080	1.0				10.00	
		2	26				1.10	.030	1.4			13.00	26.00	2.90
		4	2				.80	.030	1.2					
		5	1				.50	.020	8.0					
		7	17				.60	-.020	1.5					
		8	13				.10	-.020	.8					
		9	8				.60	.050	1.3					
		10	15				-.10	-.020	.5					
		11	13				.30	-.020	1.3					
		12	16				-.10	-.020	1.3					
	81	2	12				.10	.020	.9					
		3	11				.10	.030	1.1					
LWD603	80	1	22					.200	100.0			1.50		
		2	26				6.10	.100	13.0			5.00	11.00	
		3	20				3.90		10.0					
		4	2				12.00	.080	12.0					
			16				5.10		13.0					
		5	1				5.30	-.020	28.0					
		6	26				5.10		19.0					
		7	17				4.10	-.020	21.0					
		8	13				4.20	-.020	20.0					
		9	8				5.30	.050	21.0		-.5			
		10	15				4.50	.020	19.0					
		11	24				7.50		16.0					
		12	16				1.00	.030	2.3					
	81	3	11				5.60	.090	14.0					
LWD604	80	1	22					1.500	63.0			24.00	28.00	.75
		2	26				26.00	.400	71.0				6.00	
		3	20				13.00		41.0					
		4	2				22.00	.080	49.0					
			16				18.00		70.0					
		5	1				28.00	.100	53.0					
			15											
		6	26				10.00		54.0					
		7	17				9.80	.020	47.0					
			30				10.00		51.0					
		8	13				7.00	-.020	50.0					

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	FECAL COLIF COLONY /100 ML	TOTAL COLIF COLONY /100 ML	SO3 (MG/L)	N KJELD. (MG/L)	FE (MG/L)	MG (MG/L)	AG (MG/L)	TOC (MG/L)	ALPHA (PCI/1)	BETA (PCI/1)	RADIUM 226 (PCI/1)
LWD604	80	9	8				8.10	.050	57.0		-.5			
			18				8.40		53.0					
		10	15				17.00	.020	65.0					
			30				5.60	.070	71.0					
		11	13				5.60	.040	64.0					
			24				22.00		70.0					
		12	16				4.50	.030	11.0					
			23											
	81	1	14				4.00	.080	70.0					
		2	12				5.60	.020	73.0					
		3	11				4.20	.040	80.0					
LWD605	80	1	30				2600.00	.070	56.0			11.00	29.00	1.80
		2	26				310.00	.100	48.0		220.0			
		3	20				280.00		33.0					
		4	2				280.00	.200	37.0					
			16				280.00		51.0					
		5	1				270.00	.020	44.0					
		6	26				200.00		32.0					
		7	17				200.00	.090	30.0					
			30				180.00		25.0					
		8	13				90.00	.020	23.0					
			26				190.00		33.0					
		9	8				120.00	.300	30.0					
			18				110.00		22.0					
		10	15				62.00	.050	23.0					
			30				59.00	.030	26.0					
		11	13				45.00	.040	23.0					
			24				45.00		27.0					
		12	16				11.00							
			23				11.00	.030	29.0					
	81	1	14				17.00	.040	31.0					
		2	12				120.00	.020	27.0					
		3	11				64.00	.080	20.0					
LWD606	80	8	13				9.20	.040	160.0					
		9	8				16.00	.080	240.0					
		10	15				15.00	.040	240.0					
		12	23				10.00	.080	260.0					
	81	1	14				12.00	.080	230.0					
		2	12				12.00	.020	240.0					
		3	11				7.20	.040	230.0					

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	FECAL COLIF COLONY /100 ML	TOTAL COLIF COLONY /100 ML	SO3 (MG/L)	N KJELD. (MG/L)	FE (MG/L)	MG (MG/L)	AG (MG/L)	TOC (MG/L)	ALPHA (PCI/1)	BETA (PCI/1)	RADIUM 226 (PCI/1)
LWD607	80	1	3	-1.0	-1.00		1.60	.030	2.0	-.010	9.0	27.00	38.00	.26
			22					.400	3.1			45.00	83.00	.50
		8	13				7.80	-.020	50.0					
		12	23				7.80	.030	12.0					
	81	3	11				20.00	.090	60.0					
LWD608	80	4	2				65.00	.070	49.0					
		9	18											
							15.00	.020	51.0		29.0			
		12	22				28.00	.030	80.0					
	81	1	14				28.00	.040	64.0					
LWD610	80	2	5											
			26				17.00	.600	12.0			8.30	23.00	1.30
		3	20				7.00		3.6					
		4	2				2.80	.500	3.5					
			16				20.00		8.5					
		5	1				17.00	.300	14.0					
			15				13.00		4.5					
		6	12				20.00	.300	4.2					
		7	17				20.00	.300	4.7					
		8	13				16.00	.300	3.9					
		9	8				20.00	.600	4.6					
		10	15				21.00	.030	4.0					
		11	13				19.00	.500	4.7					
		12	16				17.00	.400	.8	-.010				
	81	2	12				40.00	.300	3.9					
		3	11				16.00	.600	4.5					
LWD611	80	2	5											
			26				46.00	.500	5.3			12.00	36.00	.56
		6	12				10.00	.100	3.3					
		7	17				4.60	.800	4.6					
							4.60	.800	4.6					
		11	13				17.00	.800	4.4					
		12	16				21.00	.800	.7	-.010				
	81	2	12				3.90	.600	3.7					
		3	11				11.00	1.600	4.0					

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	S203 (MG/L)	HG (MG/L)	SE (MG/L)	S04 (MG/L)	CL (MG/L)	F (MG/L)	SI (MG/L)	NO3 (MG/L)	NA (MG/L)	K (MG/L)	AS (MG/L)
LWD601	81	4	30											
LWD602	80	1	10	-1.00	-.020	-.020	910.00	52.00	1.40	9.3	8.00	430.0	3.10	-.020
			22				120.00	52.00	1.00		-.10	370.0	4.20	-.020
		2	26	-1.00	-.020	-.020	400.00	42.00	1.10		-.10	400.0	4.10	-.020
		4	2			-.010	410.00	69.00	1.40		74.00	410.0	3.60	-.020
		5	1			-.010	400.00	69.00	1.00		12.00	370.0	3.20	-.020
		7	17			-.010	400.00	30.00	.70		14.00	370.0	3.20	-.020
		8	13				390.00	43.00	1.20		12.00	380.0	2.20	-.020
		9	8			.010	400.00	41.00	2.00		17.00	360.0	2.10	-.020
		10	15			.010	380.00	51.00	1.10		14.00	400.0	1.00	.020
		11	13			.020	400.00	26.00	.70	12.0	9.60	370.0	1.30	-.020
		12	16		-.002	.010	400.00	45.00	1.00	10.0	15.00	410.0	3.80	-.020
	81	2	12			-.010	390.00	52.00	.90	10.0	10.00	410.0	6.40	-.020
		3	11			.010	390.00	48.00	.90	10.0	14.00	430.0	6.30	-.020
LWD603	80	1	22				470.00	80.00	3.40		-.10	600.0	9.20	-.020
		2	26	-1.00	-.020	-.020	450.00	76.00	3.70		-.10	650.0	8.50	.030
		3	20					110.00	3.50		30.00	670.0	7.90	-.020
		4	2			-.010	460.00	110.00	3.50		40.00	670.0	6.70	-.020
			16					130.00	3.50		7.50	590.0	6.00	-.020
		5	1			-.010	540.00	160.00	5.00		14.00	660.0	7.30	.040
		6	26					64.00	4.20		8.70	610.0	7.50	-.020
		7	17			-.010	610.00	66.00	2.90		14.00	640.0	8.10	-.020
		8	13				620.00	72.00	3.10		8.00	610.0	5.80	-.020
		9	8			.020	620.00	70.00	4.00		1.40	600.0	5.40	-.020
		10	15			.020	560.00	73.00	5.10		12.00	690.0	3.60	.030
		11	24					74.00	3.90		11.00	680.0	8.00	-.020
		12	16		-.002	.010	510.00	79.00	4.60	26.0	9.60	680.0	7.70	-.020
	81	3	11			.010	580.00	98.00	6.00	22.0	14.00	880.0	8.90	-.020
LWD604	80	1	22				940.00	93.00	9.80		170.00	1100.0	12.00	.080
		2	26	1.10	-.020	-.020	890.00	120.00	7.00		170.00	1100.0	11.00	.020
		3	20					110.00	5.30		30.00	890.0	7.90	.080
		4	2			-.010	800.00	100.00	5.90		28.00	840.0	9.50	.050
			16					120.00	6.50		34.00	900.0	8.50	.040
		5	1			-.010	890.00	120.00	6.50		39.00	770.0	8.00	.020
			15											
		6	26					52.00	5.60		11.00	640.0	8.20	-.020
		7	17			-.010	770.00	51.00	3.40		12.00	620.0	8.10	-.020
			30					49.00	3.20		9.60	620.0	5.60	.020
		8	13				750.00	53.00	4.10		9.20	600.0	6.20	-.020
			26					43.00	2.70		8.70	590.0	7.10	-.020
		9	8			.020	690.00	41.00	4.00		12.00	530.0	5.40	-.020
			18					44.00	5.60		10.00	500.0	6.50	.030

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	S203 (MG/L)	HG (MG/L)	SE (MG/L)	SO4 (MG/L)	CL (MG/L)	F (MG/L)	SI (MG/L)	NO3 (MG/L)	NA (MG/L)	K (MG/L)	AS (MG/L)
LWD604	80	10	15			.020	690.00	40.00	3.80		8.70	580.0	4.00	.020
			30			-.010	640.00	40.00	2.30	22.0	8.00	510.0	6.30	-.020
		11	13			.020	650.00	36.00	2.50	22.0	7.70	460.0	4.50	-.020
			24					33.00	2.10		7.70	470.0	6.60	-.020
		12	16		-.002	.010	600.00	33.00	2.30	24.0	8.20	430.0	6.50	-.020
			23											
	81	1	14			-.010	660.00	48.00	2.90	21.0	8.70	480.0	7.00	-.020
		2	12			-.010	750.00	52.00	2.30	19.0	18.00	530.0	8.70	-.020
		3	11			.020	750.00	54.00	2.50	20.0	21.00	490.0	7.60	-.020
LWD605	80	1	30				420.00	350.00	12.00	19.0	180.00	1800.0	120.00	.020
		2	26		-.020		420.00	350.00	13.00		62.00	1500.0	9.30	.020
		3	20					470.00	18.00		180.00	1400.0	70.00	.020
		4	2			-.010	230.00	500.00	20.00		140.00	1500.0	86.00	.020
			16					410.00	17.00		98.00	1300.0	68.00	.020
		5	1			.020	350.00	440.00	17.00		120.00	1200.0	60.00	.020
		6	26					350.00	27.00		32.00	1400.0	75.00	.020
		7	17			-.010	340.00	370.00	34.00		300.00	1400.0	73.00	.020
			30					350.00	38.00		21.00	1300.0	43.00	.030
		8	13				420.00	360.00	31.00		32.00	1200.0	41.00	.030
			26					310.00	18.00		28.00	1300.0	49.00	.030
		9	8			.020	490.00	330.00	24.00		28.00	1300.0	37.00	.030
			18					330.00	37.00		26.00	1400.0	36.00	.030
		10	15			.030	580.00	250.00	19.00		16.00	980.0	17.00	.200
			30			.010	550.00	190.00	14.00	22.0	14.00	830.0	22.00	.300
		11	13			.040	540.00	200.00	15.00	22.0	13.00	790.0	21.00	.200
			24					180.00	13.00		15.00	740.0	17.00	.300
		12	16											
			23		-.002	-.010	510.00	220.00	11.00	21.0	450.00	610.0	9.40	.200
	81	1	14			-.010	500.00	180.00	10.00	22.0	390.00	590.0	10.00	-.020
		2	12			-.010	490.00	130.00	11.00	19.0	280.00	650.0	14.00	.200
		3	11			.020	530.00	190.00	13.00	20.0	160.00	1000.0	27.00	.200
LWD606	80	8	13				6000.00	1300.00	3.00		31.00	2800.0	83.00	.020
		9	8			.060	5900.00	1300.00	4.00		36.00	3100.0	83.00	.020
		10	15			.080	6000.00	1200.00	4.40		24.00	3400.0	64.00	.040
		12	23		-.002	.070	5900.00	1100.00	3.90	13.0	70.00	3200.0	77.00	.050
	81	1	14			.060	6000.00	1100.00	4.20	13.0	60.00	3300.0	80.00	.030
		2	12			.050	5900.00	1100.00	3.80	12.0	43.00	3300.0	82.00	.040
		3	11			.100	5900.00	1100.00	3.90	12.0	40.00	3600.0	100.00	.030
LWD607	80	1	3	-1.00	-.020	-.020	520.00	57.00	1.10	10.0	-.10	460.0	4.60	-.020
			22				420.00	64.00	1.10		-.10	420.0	6.50	.020
		8	13				2400.00	700.00	2.90		-.50	1500.0	28.00	-.020
		12	22		-.002	.020	1600.00	940.00	4.70	11.0	100.00	1800.0	60.00	.030

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	S203 (MG/L)	HG (MG/L)	SE (MG/L)	SO4 (MG/L)	CL (MG/L)	F (MG/L)	SI (MG/L)	NO3 (MG/L)	NA (MG/L)	K (MG/L)	AS (MG/L)
LWD607	81	3	11			.050	1700.00	880.00	5.10	14.0	200.00	2000.0	60.00	.030
LWD608	80	4	2			-.010	810.00	140.00	6.70		350.00	660.0	48.00	.080
		9	18			.020	1200.00	58.00	7.60	14.0	330.00	460.0	170.00	-.020
		12	22			-.010	1200.00	170.00	9.90	14.0	280.00	740.0	68.00	.060
	81	1	14			.020	950.00	100.00	6.50	17.0	310.00	880.0	78.00	.030
LWD610	80	2	5					340.00	36.00		310.00			.200
			26	47.00	-.020	-.020	31.00	390.00	35.00		260.00	4200.0	24.00	.080
		3	20					390.00	36.00		370.00	3200.0	15.00	.150
		4	2			.030	-5.00	380.00	41.00		340.00	3600.0	44.00	.200
			16					440.00	39.00		400.00	3200.0	14.00	.200
		5	1			-.010	-5.00	490.00	43.00		370.00	3300.0	16.00	.100
			15					130.00	.50		400.00	2800.0	20.00	.100
		6	12			.040	-5.00	290.00	48.00		480.00	4100.0	18.00	.100
		7	17			-.010	-5.00	350.00	54.00		540.00	3500.0	22.00	.100
		8	13				-5.00	390.00	46.00		640.00	3400.0	17.00	.100
		9	8			-.010	-5.00	380.00	37.00		520.00	3900.0	18.00	.100
		10	15			-.010	-5.00	400.00	36.00		680.00	2900.0	13.00	.100
		11	13			.030	-5.00	400.00	41.00	14.0	540.00	4100.0	24.00	.100
		12	16		-.002	-.010	-5.00	370.00	49.00	12.0	580.00	4300.0	25.00	.090
	81	2	12			-.010	-5.00	430.00	50.00	12.0	580.00	4000.0	30.00	.060
		3	11			-.010	-5.00	410.00	48.00	12.0	540.00	4500.0	28.00	.090
LWD611	80	2	5											
			26	21.00	-.020	-.020	20.00	290.00	36.00		600.00	3400.0	16.00	.200
		6	12			.040	840.00	170.00	26.00		24.00	1900.0	9.70	.030
		7	17			-.010	690.00	250.00	30.00		280.00	2100.0	14.00	.070
						-.010	690.00	250.00	30.00		280.00	2100.0	14.00	.070
		11	13			.050	480.00	420.00	32.00	13.0	740.00	3200.0	19.00	.100
		12	16		-.002	.020	440.00	460.00	39.00	12.0	860.00	3500.0	20.00	.100
	81	2	12			.010	440.00	480.00	42.00	12.0	650.00	3700.0	28.00	.100
		3	11			.070	480.00	490.00	42.00	12.0	740.00	4100.0	26.00	.200

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	TOT ALK (MG/L CACO3)	HCO3 (MG/L CACO3)	CO3 (MG/L CACO3)	TDS (MG/L)	TOT. SUSP. SOLID (MG/L)	TURB. NTU	COD (MG/L)	PHEN (MG/L)	BOD5 (MG/L)	DOC (MG/L)	OIL AND GREASE (MG/L)
LWD601	81	4	30								-.001			
LWD602	80	1	10	420.0	260.0	160.0	1200.0	6.0	26.0	2.0	-.001	25.00	3.00	23.00
			22	400.0	250.0	150.0	1100.0	30.0	14.0	13.0	-.001	21.00		1.00
		2	26	390.0	210.0	180.0	1100.0	5.0	14.0	18.0	-.001	19.00	12.00	2.00
		4	2	420.0	230.0	190.0	1100.0	42.0	41.0	19.0	-.001		18.00	10.00
		5	1	430.0	260.0	170.0	1000.0	51.0	38.0	54.0	.008			4.00
		7	17	400.0	240.0	160.0	1100.0	22.0	15.0	4.0	-.001		6.00	6.00
		8	13	440.0	260.0	180.0	1100.0	6.0	14.0	20.0	.030			9.00
		9	8	420.0	250.0	170.0	1100.0	30.0	16.0	12.0	-.001			11.00
		10	15	400.0	200.0	200.0	1100.0	17.0	20.0	-1.0	.001		44.00	3.00
		11	13	400.0	200.0	200.0	1100.0	54.0	13.0	12.0	.002		34.00	4.00
		12	16	430.0	250.0	180.0	1100.0	22.0	19.0	-1.0	.001		46.00	3.00
	81	2	12	430.0	170.0	260.0	1100.0	29.0	27.0	-1.0	.008		34.00	8.00
		3	11	430.0	200.0	230.0	1100.0	23.0	18.0	8.0	-.001		42.00	-1.00
LWD603	80	1	22	810.0	730.0	80.0	1800.0	5.0	17.0	92.0	.009	1.00		3.00
		2	26	900.0	790.0	110.0	1900.0	37.0	42.0	100.0	.004	1.00	36.00	1.00
		3	20	970.0	850.0	120.0					-.001		46.00	
		4	2	950.0	850.0	100.0	1900.0	140.0	140.0	120.0	-.001		36.00	7.00
			16	990.0	850.0	140.0					.005		46.00	
		5	1	1100.0	990.0	94.0	2100.0	90.0	33.0	92.0	.010			14.00
		6	26	990.0	890.0	100.0					.004		110.00	
		7	17	940.0	860.0	80.0	2000.0	350.0	170.0	88.0	.004		23.00	-1.00
		8	13	950.0	890.0	60.0	1900.0	630.0	120.0	80.0	.009			15.00
		9	8	950.0	880.0	66.0	2000.0	360.0	96.0	96.0	.009			10.00
		10	15	890.0	870.0	22.0	1900.0	610.0	150.0	180.0	.010		49.00	2.00
		11	24	870.0	780.0	88.0					.009		24.00	
		12	16	960.0	910.0	54.0	1900.0	120.0	63.0	130.0	.009		72.00	2.00
	81	3	11	950.0	800.0	150.0	2100.0	230.0	170.0	110.0	.010		37.00	2.00
LWD604	80	1	22	1700.0	1600.0	100.0	3700.0	12.0	40.0	280.0	.007	1.00		13.00
		2	26	1400.0	1300.0	100.0	3100.0	18.0	23.0	250.0	.004	650.00	76.00	16.00
		3	20	1300.0	1100.0	150.0					-.001		84.00	
		4	2	1400.0	1200.0	170.0	2900.0	59.0	50.0	100.0	-.001		87.00	10.00
			16	1500.0	1400.0	100.0					.007		93.00	
		5	1	1400.0	1200.0	200.0	2800.0	100.0	33.0	250.0	.010			6.00
			15											
		6	26	900.0	810.0	92.0					.001		110.00	
		7	17	910.0	830.0	76.0	2100.0	62.0	45.0	100.0	-.001		28.00	98.00
			30	880.0	820.0	56.0					-.001		32.00	
		8	13	960.0	890.0	68.0	2100.0	120.0	32.0	120.0	-.001			14.00
			26	910.0	840.0	74.0					-.001		29.00	
		9	8	900.0	870.0	32.0	2000.0	31.0	23.0	79.0	.004			8.00

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	TOT ALK (MG/L CACO3)	HCO3 (MG/L CACO3)	CO3 (MG/L CACO3)	TDS (MG/L)	TOT. SUSP. SOLID (MG/L)	TURB. NTU	COD (MG/L)	PHEN (MG/L)	BOD5 (MG/L)	DOC (MG/L)	OIL AND GREASE (MG/L)
LWD604	80	9	18	860.0	830.0	28.0					-.001		31.00	
		10	15	840.0	810.0	28.0	1900.0	7.0	14.0	74.0	.004		48.00	2.00
			30	770.0	710.0	64.0	1800.0	15.0	15.0	120.0	.016		22.00	7.00
		11	13	750.0	750.0	-1.0	1800.0	49.0	14.0	66.0	-.001		60.00	3.00
			24	710.0	680.0	34.0					.003		43.00	
		12	16	700.0	660.0	40.0	1600.0	3.0	13.0	32.0	.002		61.00	11.00
			23											
	81	1	14	710.0	650.0	64.0	1800.0	12.0	18.0	160.0	.016		48.00	1.00
		2	12	720.0	670.0	48.0	2000.0	18.0	22.0	44.0	-.001		60.00	7.00
		3	11	640.0	560.0	80.0	1800.0	12.0	21.0	31.0	-.001		61.00	2.00
LWD605	80	1	30	5500.0	2300.0	3200.0	5200.0	120.0			3.400		330.00	110.00
		2	26	3500.0	2400.0	1100.0	4400.0	100.0			5.800		220.00	8.00
		3	20	3900.0	2700.0	1200.0					3.400		230.00	
		4	2	4000.0	2800.0	1200.0	4600.0	48.0	22.0	240.0	5.000		74.00	6.00
			16	3700.0	2900.0	800.0					2.500		190.00	
		5	1	3600.0	2300.0	1300.0	4200.0	24.0	24.0	750.0	2.300			2.00
		6	26	3100.0	1900.0	1200.0					1.600		260.00	
		7	17	3100.0	1500.0	1600.0	4300.0	58.0	32.0	880.0				19.00
			30	3000.0	1400.0	1600.0					.080		190.00	
		8	13	3100.0	2200.0	940.0	4100.0	47.0	18.0	640.0	.900			32.00
			26	2600.0	2000.0	590.0					.470		150.00	
		9	8	2600.0	1100.0	1500.0	4000.0	39.0	17.0	480.0	.400			13.00
			18	2300.0	920.0	1400.0					.005		170.00	
		10	15	1500.0	1000.0	490.0	2900.0	34.0	17.0	360.0	.070		190.00	2.00
			30	1200.0	690.0	520.0	2400.0	29.0	18.0	140.0	.044		60.00	1.00
		11	13	1300.0	720.0	530.0	2600.0	80.0	22.0	3100.0	.050		110.00	19.00
			24	1000.0	650.0	380.0					.034		88.00	
		12	16							160.0	.002		32.00	15.00
			23	760.0	590.0	170.0	2000.0	16.0	11.0	160.0	.007		54.00	1.00
	81	1	14	710.0	510.0	200.0	1800.0	23.0	12.0	70.0	.080		61.00	-1.00
		2	12	790.0	590.0	200.0	2000.0	10.0	10.0	440.0	.010		60.00	-1.00
		3	11	1400.0	820.0	600.0	2500.0	16.0	15.0	200.0	.850		120.00	3.00
LWD606	80	8	13	330.0	-1.0	330.0	11000.0	460.0	98.0	360.0	.030			20.00
		9	8	300.0	43.0	260.0	11000.0	85.0	37.0	400.0	.020			4.00
		10	15	270.0	130.0	140.0	11000.0	320.0	92.0	300.0	.020		140.00	5.00
		12	23	330.0	250.0	80.0	11000.0	590.0	290.0	290.0	.020		180.00	-1.00
	81	1	14	360.0	300.0	62.0	11000.0	2,200.0	400.0	360.0	.035		120.00	3.00
		2	12	360.0	290.0	66.0	11000.0	390.0	230.0	330.0	.028		180.00	2.00
		3	11	420.0	370.0	50.0	11000.0	150.0	56.0	120.0	.006		150.00	1.00
LWD607	80	1	3	390.0	210.0	180.0	1300.0	75.0	15.0	21.0	.290	37.00	8.00	3.00
			22	370.0	230.0	140.0	1300.0	56.0	36.0	20.0	.009	3.00		10.00

LOGAN WASH
WATER QUALITY PARAMETERS
RETORT 6 WELLS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	TOT ALK (MG/L CACO3)	HCO3 (MG/L CACO3)	CO3 (MG/L CACO3)	TDS (MG/L)	TOT. SUSP. SOLID (MG/L)	TURB. NTU	COD (MG/L)	PHEN (MG/L)	BOD5 (MG/L)	DOC (MG/L)	OIL AND GREASE (MG/L)
LWD607	80	8	13	320.0	140.0	180.0	4700.0	1,100.0	300.0	250.0	.010			5.00
		12	23	1000.0	410.0	620.0	2700.0	1,800.0	370.0	800.0	.020		350.00	-1.00
	81	3	11	1400.0	1400.0	-1.0	5900.0	120.0	67.0	12000.0	.030		3500.00	8.00
LWD608	80	4	2	780.0	580.0	200.0	2500.0	75.0	76.0	240.0	-.001		220.00	2.00
		9	18	340.0	240.0	96.0	2300.0	120.0			-.001			1.00
		12	22	630.0	520.0	110.0	3000.0	120.0	73.0	70.0	.040		68.00	2.00
	81	1	14	450.0	350.0	96.0	2200.0	70.0	52.0	120.0	.053		68.00	8.00
LWD610	80	2	5	6600.0	6200.0	420.0								
			26	6800.0	5800.0	1000.0	11000.0	500.0	150.0	3300.0	.005	370.00	1200.00	21.00
		3	20	6600.0	5900.0	680.0					-.001		1100.00	
		4	2	6800.0	5800.0	1000.0	10000.0	78.0	23.0	410.0	-.001		1100.00	33.00
			16	7800.0	7100.0	700.0					.009		1000.00	
		5	1	6900.0	6800.0	110.0	11000.0	200.0	71.0	11000.0	.020			18.00
			15	7900.0	7000.0	920.0					.012		840.00	
		6	12	7700.0	6400.0	1300.0	11000.0	31.0	40.0	3200.0	.012			10.00
		7	17	7800.0	6600.0	1200.0	11000.0	38.0	15.0	3700.0	-.001		810.00	16.00
		8	13	8100.0	7200.0	920.0	11000.0	52.0	100.0	3500.0	.006			12.00
		9	8	810.0	710.0	96.0	11000.0	44.0	14.0	3000.0	-.001			15.00
		10	15	7900.0	7000.0	900.0	10000.0	37.0	12.0	3400.0	.005		910.00	3.00
		11	13	7900.0	6700.0	1200.0	10000.0	340.0	45.0	200.0	.010		1100.00	16.00
		12	16	8200.0	7300.0	860.0	11000.0	110.0	17.0	2600.0	.008		940.00	3.00
	81	2	12	8000.0	7000.0	1000.0	11000.0	42.0	15.0	2600.0	.038		890.00	4.00
		3	11	8200.0	7200.0	1000.0	11000.0	94.0	17.0	2200.0	.003		37.00	5.00
LWD611	80	2	5											
			26	10000.0	9000.0	1000.0	9200.0	1,900.0	40.0	3300.0	.010	1300.00	1600.00	8.00
		6	12	2200.0	1600.0	600.0	5000.0	220.0	86.0	250.0	.008			19.00
		7	17	3800.0	3200.0	680.0	6400.0	160.0	77.0	2200.0	-.001		420.00	1.00
				3900.0	3200.0	680.0	6400.0	160.0	77.0	2200.0	-.001		420.00	1.00
		11	13	5900.0	4900.0	960.0	8600.0	310.0	30.0	2500.0	.020		960.00	2.00
		12	16	6100.0	5200.0	920.0	7100.0	170.0	35.0	2600.0	.001		950.00	2.00
	81	2	12	6700.0	5500.0	1200.0	9900.0	53.0	16.0	7000.0	-.001		1100.00	1.00
		3	11	6900.0	5700.0	1200.0	9500.0	570.0	110.0	3000.0	.026		1100.00	4.00

LOGAN WASH
WATER QUALITY PARAMETERS
STREAMS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	CA (MG/L)	B (MG/L)	CU (MG/L)	V (MG/L)	MO (MG/L)	LI (MG/L)	ZN (MG/L)	AL (MG/L)	BA (MG/L)	SR (MG/L)	AMMONIA AS N (MG/L)
LWS001	80	5	8	91.0	-.100	.050	-.050	.030	.050	.010	-.100	-.500	1.30	-.04
		6	19	350.0	.200								6.10	-.04
LWS002	80	2	20	47.0	.200	-.020	-.050	.010	-.050	.020	2.400	.500	.80	.10
		3	27	200.0	.200	-.010	-.050	.050	.200	.020	-.100	1.000	3.00	.60
		5	8	130.0	.200	.020	-.050	.050	-.050	-.010	-.100	.900	3.50	.50
		6	3	120.0	.400	.090	-.050	.100	.060	.060	-.100	-.500	6.20	.08
		8	6	170.0	.400	-.020	-.050	.100	.100	-.020	-.100	-.500	7.20	.50
		9	4	180.0	.400	.020	-.050	.100	.100	-.020	-.100	-.500	3.90	-.04
		10	2	220.0	.400	.030	-.050	.070	.100	-.020	-.100	-.500	4.10	.06
LWS003	80	1	9	67.0	.400	-.020	-.050	.030	.050	-.020	-.100	-.500	3.60	.08
		2	7	66.0	.200	-.020	-.050	.030	.050	-.020	-.100	.500	3.50	-.04
		3	6	78.0	.200	.020	-.050	.030	.050	-.020	-.100	.500	2.20	-.04
		4	10	110.0	.200	-.020	-.050	.030	.050	.030	-.100	.500	.20	.05
		5	8	99.0	.100	-.020	-.050	.030	-.050	.030	-.100	-.500	1.10	-.04
		6	3	55.0	-.100	.060	-.050	.050	-.050	.030	-.100	-.500	1.40	.05
		7	3	65.0	.200	-.020	-.050	.100	.050	-.010	-.100	-.500	1.60	.05
		8	6	74.0	.200	-.020	-.050	.040	.060	-.020	-.100	-.500	2.90	.20
		9	4	79.0	.200	.020	-.050	.070	.070	-.020	-.100	-.500	1.40	-.04
		10	2	88.0	.300	.030	-.050	.040	.050	-.020	-.100	-.500	1.40	.10
		11	6	100.0	.100	-.020	-.050	.050	.060	-.020	-.100	-.500	2.10	-.04
		12	4	120.0	.300	-.020	-.050	.040	.050	-.020	-.100	-.500	2.00	-.04
	81	1	8	120.0	.200	.020	-.050	.030	.060	-.020	-.100	-.500	1.60	.08
		2	4	94.0	.200	.030	-.050	.030	.060	-.020	-.100	-.500	1.30	.05
		3	5	93.0	.200	.020	-.050	.030	.050	-.020	-.100	-.500	1.60	-.04
LWS004	80	3	6	140.0	.400	-.020	-.050	.100	.100	-.020	-.100	.500	3.20	.04
		4	10	170.0	.300	-.010	-.050	.090	.200	.030	-.100	.500	.30	-.04
		5	8	150.0	.400	.020	-.050	.200	.200	.010	-.100	.500	3.10	-.04
		6	3	120.0	.400	.060	-.050	.200	.100	.020	-.100	.500	4.40	-.04
		7	3	110.0	.500	-.020	-.050	.400	.200	-.010	-.100	-.500	3.40	.05
		8	6	130.0	.400	-.020	-.050	.200	.200	-.020	-.100	-.500	5.30	.80
		9	4	58.0	.500	-.020	-.050	.300	.200	-.020	-.100	-.500	1.70	-.04
		10	2	88.0	.500	-.020	-.050	.200	.200	-.020	-.100	-.500	1.70	-.04
		11	6	98.0	.100	-.020	-.050	.200	.200	-.020	-.100	-.500	2.40	-.04
LWS005	80	4	23	130.0	.200	.020	-.050	.070	.070	.020	-.100	-.500	.20	-.04
		10	16	240.0	-.100	-.020	-.050	.020	-.050	-.020	-.100	-.500	3.80	.60
LWS006	80	7	23	69.0	.100	-.020	-.050	.060	.060	-.020	-.100	-.500	3.60	-.04
				69.0	.100	-.020	-.050	.060	.060	-.020	-.100	-.500	6.00	-.04
		10	16	84.0	-.100	-.020	-.050	.040	-.050	-.020	-.100	-.500	2.50	-.04

LOGAN WASH
WATER QUALITY PARAMETERS
STREAMS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	CA (MG/L)	B (MG/L)	CU (MG/L)	V (MG/L)	MO (MG/L)	LI (MG/L)	ZN (MG/L)	AL (MG/L)	BA (MG/L)	SR (MG/L)	AMMONIA AS N (MG/L)
LWS007	80	1	16	65.0	.200	-.020	-.050	.030	-.050	-.020	-.100	-.500	3.20	1.20
		4	23	110.0	-.100	-.020	-.050	.010	-.050	.020	-.100	-.500	.10	.30
		7	23	81.0	.200	-.020	-.050	.050	-.050	-.020	-.100	-.500	2.70	.07
		10	16	110.0	.200	-.020	-.050	.040	-.050	-.020	-.100	-.500	2.80	.30
	81	1	29	90.0	.200	-.020	-.050	.030	-.050	-.020	-.100	-.500	1.40	.04
LWS013	80	1	9	72.0	.200	-.020	-.050	.030	.050	-.020	-.100	-.500	3.70	-.04
		2	7	68.0	.200	-.020	-.050	.030	.050	-.020	.200	-.500	3.60	-.04
		3	6	78.0	.400	.020	-.050	.030	.060	-.020	-.100	.500	2.20	.10
		4	10	100.0	.200	-.020	-.050	.030	.050	.020	-.100	.500	.20	-.04
		5	8	96.0	-.100	.040	-.050	.030	-.050	.020	-.100	.500	1.00	.40
		6	3	55.0	-.100	.040	-.050	.050	-.050	.030	-.100	-.500	1.40	.10
		7	3	63.0	.200	-.020	-.050	.100	.050	-.010	-.100	-.500	1.60	.30
		8	6	74.0	.200	-.020	-.050	.040	.060	-.020	-.100	-.500	2.90	-.04
		9	4	78.0	.200	-.020	-.050	.060	.070	-.020	-.100	-.500	1.40	-.04
		10	2	91.0	.300	.020	-.050	.040	.050	-.020	-.100	-.500	1.40	.08
		11	6	100.0	.300	-.020	-.050	.040	.060	.300	-.100	-.500	2.10	-.04
		12	4	120.0	.300	.020	-.050	.040	.050	-.020	-.100	-.500	2.00	-.04
	81	1	8	120.0	.200	.020	-.050	.040	.060	-.020	-.100	-.500	1.60	.09
		2	4	94.0	.200	.020	-.050	.030	.060	-.020	-.100	-.500	1.30	.04
		3	5	94.0	.200	-.020	-.050	.030	.050	-.020	-.100	-.500	1.60	-.04
LWS017	80	1	16	67.0	-.100	-.020	-.050	.030	-.050	-.020	-.100	-.500	3.10	-.04
		4	23	100.0	-.100	.030	-.050	.010	-.050	.020	-.100	-.500	.10	.10
		7	23	88.0	.200	-.020	-.050	.060	-.050	-.020	-.100	-.500	2.70	-.04
		10	15	100.0	.200	-.020	-.050	.040	-.050	-.020	-.100	-.500	2.80	-.04
	81	1	29	90.0	.200	-.020	-.050	.040	.050	-.020	-.100	-.500	1.50	.04

LOGAN WASH
WATER QUALITY PARAMETERS
STREAMS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	FECAL COLIF COLONY /100 ML	TOTAL COLIF COLONY /100 ML	SO3 (MG/L)	N KJELD. (MG/L)	FE (MG/L)	MG (MG/L)	AG (MG/L)	TOC (MG/L)	ALPHA (PCI/1)	BETA (PCI/1)	RADIUM 226 (PCI/1)
LWS001	80	5	8				.60	.020	48.0			5.30	35.00	2.50
		6	19				.70		180.0					
LWS002	80	2	20				2.20	1.800	26.0			123.00	463.00	.39
		3	27				.60	-.020	120.0			58.00	34.00	.35
		5	8				1.30	-.020	63.0			12.00	15.00	
		6	3				1.40	.020	130.0			6.00	19.00	
		8	6				1.10	-.020	150.0			5.90	13.00	
		9	4				.80	.050	160.0		-.5	5.90	14.00	
		10	2				.07	.020	190.0				9.10	
LWS003	80	1	9	-1.0	-1.00		-1.00	-.020	76.0	-.010	6.0	1.60	19.00	
		2	7				.60	-.020	80.0			.10	1.00	
		3	6				.10	-.020	77.0			11.00	2.50	
		4	10				.30	-.020	86.0			20.00	7.00	
		5	8				.10	-.020	38.0			19.00	9.50	
		6	3				.40	-.020	35.0			8.10	7.30	
		7	3				.07	.020	61.0			17.00	16.00	
		8	6				.40	-.020	76.0			13.40	4.60	
		9	4				.10	.030	71.0			14.00	12.00	
		10	2				.10	.030	80.0				9.60	
		11	6				.10	.020	93.0			5.10	7.10	
		12	4				-.10	-.020	90.0			15.20	3.70	
	81	1	8				-.10	.020	97.0					
		2	4				.10	-.020	93.0					
		3	5				-.10	.020	98.0					
LWS004	80	3	6				.80	.020	76.0			29.00	32.00	2.40
		4	10				.50	.040	110.0			40.00	14.00	.22
		5	8				.20	-.020	81.0			1.30	14.00	
		6	3				.70	.030	94.0			19.00	24.00	.86
		7	3				.40	.020	98.0			22.00	26.00	
		8	6				.80	-.020	98.0			21.00	29.00	.46
		9	4				.40	.030	57.0			15.00	31.00	1.03
		10	2				.80	-.020	69.0				34.00	.23
		11	6				.10	-.020	82.0			14.00	24.00	1.20
LWS005	80	4	23				.40	-.020	81.0			27.00	65.00	.67
		10	16				1.10	.020	40.0				23.00	2.80
LWS006	80	7	23				.10	-.020	85.0			6.20	3.30	
							.10	-.020	85.0					
		10	16				.60	-.020	59.0				13.00	3.40

LOGAN WASH
WATER QUALITY PARAMETERS
STREAMS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	FECAL COLIF COLONY /100 ML	TOTAL COLIF COLONY /100 ML	SO3 (MG/L)	N KJELD. (MG/L)	FE (MG/L)	MG (MG/L)	AG (MG/L)	TOC (MG/L)	ALPHA (PCI/1)	BETA (PCI/1)	RADIUM 226 (PCI/1)
LWS007	80	1	16					.070	55.0			1.50	11.00	
		4	23				.50	.080	43.0			26.00	35.00	1.80
		7	23				.30	-.020	51.0			1.70	6.60	
		10	16				.40	-.020	49.0				8.10	
	81	1	29				.50	.030	65.0					
LWS013	80	1	9	-1.0	-1.00		-1.00	.070	81.0	-.010	6.0	18.00	30.00	.04
		2	7				.07	.100	82.0			3.00	5.00	
		3	6				.30	-.020	78.0			15.00	13.00	
		4	10				.07	-.020	89.0			11.00	3.00	
		5	8				3.90	-.020	36.0			4.00	9.10	
		6	3				.80	.020	35.0			9.30	3.20	
		7	3				.40	-.020	60.0			35.00	17.00	
		8	6				.30	-.020	76.0			11.10	4.20	
		9	4				.10	.030	70.0		-.5	4.10	11.00	
		10	2				.10	-.020	80.0				9.40	
		11	6				.20	.030	93.0			9.00	7.40	
		12	4				-.10	-.020	92.0			14.80	7.40	
	81	1	8				.30	.030	94.0					
		2	4				.50	-.020	93.0					
		3	5				-.10	.030	99.0					
LWS017	80	1	16					.050	54.0			3.00	35.00	.65
		4	23				.20	-.020	47.0			24.00	27.00	1.60
		7	23				.40	-.020	52.0					
		10	15				.60	-.020	45.0				3.60	
	81	1	29				.10	.020	64.0					

LOGAN WASH
WATER QUALITY PARAMETERS
STREAMS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	S203 (MG/L)	HG (MG/L)	SE (MG/L)	SO4 (MG/L)	CL (MG/L)	F (MG/L)	SI (MG/L)	NO3 (MG/L)	NA (MG/L)	K (MG/L)	AS (MG/L)
LWS001	80	5	8			-.010	180.00	39.00	.70		7.80	90.0	4.80	-.020
		6	19				1800.00	49.00	.90		40.00	260.0	7.40	-.020
LWS002	80	2	20	-1.00	-.020	-.020	210.00	250.00	.50		5.00	54.0	7.20	-.020
		3	27			.040	1500.00	48.00	.90		14.00	280.0	10.00	-.020
		5	8			-.010	500.00	59.00	.50		40.00	120.0	6.50	-.020
		6	3			.060	980.00	84.00	.70		75.00	190.0	6.80	-.020
		8	6			-.010	1400.00	30.00	.60		59.00	260.0	7.90	-.020
		9	4			-.010	1400.00	29.00	1.80		49.00	270.0	8.40	-.020
		10	2			.010	1500.00	29.00	.60		54.00	300.0	10.00	-.020
LWS003	80	1	9	-1.00	-.020	-.020	480.00	16.00	.80	15.0	2.00	140.0	4.30	-.020
		2	7	-1.00		-.002	440.00	29.00	.80		-.10	150.0	3.50	-.020
		3	6			.100	460.00	29.00	1.00		25.00	150.0	6.80	-.020
		4	10			-.010	380.00	50.00	.90		24.00	140.0	4.10	-.020
		5	8			-.010	110.00	38.00	.50		6.70	50.0	3.70	-.020
		6	3			-.010	170.00	49.00	.60		4.40	61.0	2.20	-.020
		7	3			-.010	310.00	11.00	1.20		3.10	110.0	5.40	-.020
		8	6			-.010	440.00	13.00	.80		3.00	150.0	4.00	-.020
		9	4			-.010	480.00	13.00	2.10		3.50	160.0	5.10	-.020
		10	2			-.010	490.00	12.00	.80		2.20	160.0	5.40	-.020
		11	6			-.010	450.00	12.00	.80	16.0	3.30	150.0	4.00	-.020
		12	4			-.010	440.00	13.00	.70	15.0	4.00	150.0	3.90	-.020
	81	1	8			-.010	430.00	14.00	1.10	16.0	3.30	150.0	5.30	-.020
		2	4			-.010	430.00	14.00	.80	14.0	2.40	160.0	6.90	-.020
		3	5			-.010	490.00	13.00	.80	15.0	5.10	170.0	47.00	-.020
LWS004	80	3	6			.100	920.00	34.00	1.50		38.00	200.0	14.00	-.020
		4	10			.020	920.00	63.00	1.40		38.00	230.0	14.00	-.020
		5	8			.040	780.00	54.00	1.50		22.00	180.0	19.00	-.020
		6	3			.020	920.00	64.00	1.20		19.00	220.0	17.00	-.020
		7	3			-.010	960.00	16.00	1.80		16.00	250.0	21.00	-.020
		8	6			-.010	1100.00	17.00	1.10		6.20	260.0	18.00	-.020
		9	4			-.010	560.00	12.00	3.60		19.00	150.0	25.00	-.020
		10	2			-.010	580.00	11.00	1.50		19.00	150.0	25.00	-.020
		11	6			-.010	450.00	14.00	1.20	12.0	19.00	160.0	29.00	-.020
LWS005	80	4	23			-.010	470.00	47.00	.70		15.00	120.0	5.40	-.020
		10	16			.020	1300.00	9.50	1.00		5.10	240.0	8.40	-.020
LWS006	80	7	23			-.010	530.00	11.00	.60		.90	150.0	3.30	-.020
						-.010	530.00	11.00	.60		.90	1503.0	3.30	-.020
		10	16			-.010	400.00	9.70	.70		3.20	140.0	4.20	-.020
LWS007	80	1	16				260.00	18.00	.90		-.10	110.0	5.60	-.020

LOGAN WASH
WATER QUALITY PARAMETERS
STREAMS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	S203 (MG/L)	HG (MG/L)	SE (MG/L)	SO4 (MG/L)	CL (MG/L)	F (MG/L)	SI (MG/L)	NO3 (MG/L)	NA (MG/L)	K (MG/L)	AS (MG/L)
LWS007	80	4	23			-.010	100.00	57.00	.40		24.00	46.0	3.60	-.020
		7	23			-.010	240.00	17.00	1.10		2.20	100.0	4.10	-.020
		10	16			-.010	300.00	23.00	1.20		3.50	110.0	4.20	-.020
	81	1	29			-.010	240.00	29.00	1.10	13.0	2.00	110.0	6.40	-.020
LWS013	80	1	9	-1.00	-.020	-.020	470.00	16.00	.80	14.0	2.00	150.0	4.60	-.020
		2	7	-1.00		-.002	430.00	20.00	.80		-.10	150.0	4.50	-.020
		3	6			-.020	460.00	24.00	1.00		21.00	160.0	7.70	-.020
		4	10			-.010	410.00	42.00	.80		27.00	140.0	4.10	-.020
		5	8			-.010	110.00	41.00	.50		6.90	60.0	4.10	-.020
		6	3			.020	180.00	53.00	.60		5.30	62.0	2.40	-.020
		7	3			-.010	310.00	11.00	1.30		3.80	110.0	5.40	-.020
		8	6			-.010	440.00	13.00	.70		2.90	150.0	4.10	-.020
		9	4			-.010	480.00	13.00	1.90		3.30	160.0	5.40	-.020
		10	2			-.010	480.00	12.00	.70		2.80	160.0	5.60	-.020
		11	6			-.010	450.00	12.00	.80	16.0	4.00	150.0	4.10	-.020
		12	4			-.010	430.00	13.00	.70	15.0	4.00	150.0	3.90	-.020
	81	1	8			-.010	440.00	13.00	1.10	16.0	3.20	150.0	5.60	-.020
		2	4			-.010	430.00	14.00	.80	13.0	2.40	160.0	6.90	-.020
		3	5			-.010	490.00	13.00	.80	15.0	4.40	160.0	47.00	-.020
LWS017	80	1	16				250.00	20.00	.90		-.10	100.0	5.50	-.020
		4	23			-.010	100.00	81.00	.40		22.00	46.0	3.40	-.020
		7	23			-.010	250.00	19.00	1.10		2.00	100.0	4.00	-.020
		10	15			-.010	310.00	27.00	1.20		3.50	100.0	4.10	-.020
	81	1	29			-.010	240.00	29.00	1.20	13.0	2.40	110.0	6.90	-.020

LOGAN WASH
WATER QUALITY PARAMETERS
STREAMS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	TOT ALK (MG/L CACO3)	HCO3 (MG/L CACO3)	CO3 (MG/L CACO3)	TDS (MG/L)	TOT. SUSP. SOLID (MG/L)	TURB. NTU	COD (MG/L)	PHEN (MG/L)	BOD5 (MG/L)	DOC (MG/L)	OIL AND GREASE (MG/L)
LWS001	80	5	8	300.0	190.0	110.0	630.0	300.0	210.0	22.0	-.001	4.00		2.00
		6	19	350.0	250.0	96.0					-.001			
LWS002	80	2	20	130.0	90.0	40.0	500.0	250.0	220.0	68.0	.003	22.00	36.00	4.00
		3	27	150.0	92.0	60.0	2500.0	57.0	44.0	34.0	-.001	2.00		-1.00
		5	8	240.0	140.0	98.0	1000.0	5,800.0	130.0	4.0	-.001	4.00		9.00
		6	3	440.0	220.0	220.0	2000.0	820.0	320.0	22.0	-.001	15.00		16.00
		8	6	340.0	190.0	150.0	2500.0	13.0	10.0	26.0	-.001	48.00		10.00
		9	4	450.0	310.0	140.0	2600.0	-1.0	10.0	66.0	.010	6.00		7.00
		10	2	450.0	350.0	100.0	2900.0	8.0	1.0	38.0	-.001	1.00	55.00	-1.00
LWS003	80	1	9	400.0	320.0	80.0	1100.0	58.0	23.0	2.0	-.001	46.00	5.00	5.00
		2	7	450.0	380.0	70.0	1100.0	110.0	59.0	2.0	.020	7.00	-1.00	8.00
		3	6	400.0	300.0	100.0	1100.0	280.0	250.0	26.0	-.001	12.00	6.00	4.00
		4	10	400.0	300.0	100.0	940.0	450.0	240.0	29.0	.001	25.00	11.00	-1.00
		5	8	270.0	190.0	76.0	530.0	3,800.0	180.0	4.0	-.001	20.00		22.00
		6	3	320.0	220.0	100.0	570.0	1,400.0	360.0	140.0	-.001	92.00		12.00
		7	3	390.0	320.0	70.0	820.0	360.0	170.0	14.0	-.001	39.00		4.00
		8	6	440.0	380.0	58.0	1100.0	300.0	78.0	14.0	-.001	10.00		4.00
		9	4	440.0	320.0	120.0	1200.0	270.0	160.0	46.0	.010	10.00		6.00
		10	2	440.0	350.0	94.0	1100.0	56.0	28.0	12.0	-.001	9.00	10.00	1.00
		11	6	440.0	360.0	84.0	1100.0	76.0	43.0	8.0	.003	100.00	14.00	2.00
		12	4	440.0	370.0	74.0	1100.0	58.0	27.0	4.0	.003	33.00	20.00	-1.00
	81	1	8	420.0	340.0	78.0	1000.0	47.0	38.0	7.0	-.001	26.00	28.00	4.00
		2	4	420.0	340.0	84.0	1000.0	220.0	130.0	4.0	-.001	85.00	28.00	1.00
		3	5	450.0	360.0	86.0	1200.0	79.0	58.0	-1.0	-.001	95.00	56.00	3.00
LWS004	80	3	6	240.0	170.0	70.0	1200.0	4,100.0	46.0	9.0	.004	24.00	13.00	8.00
		4	10	250.0	160.0	90.0	1700.0	410.0	230.0	53.0	.001	20.00	14.00	4.00
		5	8	250.0	190.0	60.0	1500.0	150.0	66.0	5.0	.003	4.00		12.00
		6	3	290.0	190.0	100.0	1000.0	33.0	20.0	2.0	-.001	-1.00		4.00
		7	3	260.0	140.0	120.0	1700.0	-1.0	1.5	18.0	-.001	45.00		-1.00
		8	6	290.0	170.0	120.0	2000.0	-1.0	8.0	14.0	-.001	60.00		10.00
		9	4	230.0	110.0	120.0	1100.0	17.0	2.0	4.0	.009	5.00		16.00
		10	2	240.0	110.0	130.0	1200.0	-1.0	10.0	19.0	-.001	9.00	58.00	1.00
		11	6	190.0	190.0	-1.0	900.0	36.0	22.0	2.0	.003	20.00	7.00	2.00
LWS005	80	4	23	220.0	120.0	100.0	940.0	3,200.0	350.0	4.0	-.001	-1.00		6.00
		10	16	78.0	78.0	-1.0	2100.0	11,000.0	*****	24.0	.002	53.00	47.00	-1.00

LOGAN WASH
WATER QUALITY PARAMETERS
STREAMS
FOR SAMPLE DATA SHOWN

LOC	YR	MO	DY	TOT ALK (MG/L CACO3)	HCO3 (MG/L CACO3)	CO3 (MG/L CACO3)	TDS (MG/L)	TOT. SUSP. SOLID (MG/L)	TURB. NTU	COD (MG/L)	PHEN (MG/L)	BOD5 (MG/L)	DOC (MG/L)	OIL AND GREASE (MG/L)
LWS006	80	7	23	380.0	230.0	160.0	1100.0	8.0	12.0	30.0	.005	33.00		2.00
				390.0	230.0	160.0	1100.0	8.0	12.0	30.0	.005	33.00		2.00
		10	16	300.0	200.0	100.0	890.0	1,500.0	120.0	16.0	.001	49.00	80.00	-1.00
LWS007	80	1	16	330.0	240.0	90.0	770.0	-1.0	14.0	-1.0	.018	11.00		2.00
		4	23	250.0	130.0	120.0	460.0	900.0	240.0	25.0	-.001	1.00		3.00
		7	23	390.0	290.0	96.0	750.0	4.0	12.0	6.0	-.001	25.00		-1.00
		10	16	400.0	310.0	92.0	740.0	6.0	16.0	4.0	.003	53.00	45.00	-1.00
	81	1	29	360.0	260.0	100.0	780.0	3.0	2.0	-1.0	.005	15.00	26.00	-1.00
LWS013	80	1	9	410.0	320.0	90.0	1000.0	52.0	26.0	4.0	-.001	42.00	3.00	10.00
		2	7	430.0	380.0	50.0	1400.0	68.0	54.0	4.0	.010	2.00	12.00	6.00
		3	6	390.0	290.0	100.0	1100.0	340.0	250.0	4.0	-.001	14.00	14.00	8.00
		4	10	410.0	300.0	110.0	960.0	410.0	200.0	18.0	.002	29.00	17.00	2.00
		5	8	280.0	220.0	60.0	510.0	2,100.0	200.0	6.0	-.001	16.00		11.00
		6	3	330.0	210.0	120.0	600.0	1,600.0	350.0	9.0	-.001	24.00		2.00
		7	3	390.0	290.0	100.0	820.0	360.0	180.0	14.0	-.001	39.00		1.00
		8	6	450.0	370.0	76.0	1100.0	300.0	82.0	22.0	-.001	70.00		6.00
		9	4	450.0	320.0	130.0	1100.0	380.0	170.0	58.0	.020	21.00		5.00
		10	2	450.0	360.0	86.0	1100.0	50.0	26.0	19.0	-.001	19.00	8.00	1.00
		11	6	450.0	360.0	88.0	1000.0	60.0	39.0	52.0	-.001	100.00	19.00	2.00
		12	4	450.0	340.0	110.0	1000.0	74.0	26.0	21.0	.004	38.00	23.00	1.00
	81	1	8	420.0	350.0	70.0	1000.0	54.0	37.0	13.0	.002	28.00	41.00	4.00
		2	4	420.0	350.0	68.0	1000.0	210.0	130.0	5.0	-.001	80.00	22.00	-1.00
		3	5	440.0	370.0	68.0	1200.0	79.0	52.0	-1.0	-.001	78.00	80.00	-1.00
LWS017	80	1	16	360.0	240.0	120.0	770.0	-1.0	12.0	-1.0	.002	21.00		2.00
		4	23	250.0	180.0	70.0	470.0	1,300.0	230.0	-1.0	-.001	-1.00		4.00
		7	23	390.0	280.0	110.0	810.0	16.0	14.0	12.0	-.001	14.00		7.00
		10	15	400.0	320.0	82.0	830.0	72.0	57.0	4.0	.001	48.00	45.00	-1.00
	81	1	29	360.0	260.0	96.0	760.0	-1.0	3.0	-1.0	.008	24.00	29.00	2.00

LOGAN WASH
WATER QUALITY PARAMETERS
NPDES
FOR DATA SHOWN

LOC	YR	MO	DY	TOTAL AS (MG/L)	TOTAL B (MG/L)	TOTAL CR (MG/L)	TOTAL CU (MG/L)	TOTAL FE (MG/L)	TOTAL MO (MG/L)	TOTAL ZN (MG/L)	TOTAL F (MG/L)	TOT. SUS. SOLIDS (MG/L)	TOT. DIS. SOLIDS (MG/L)
LWM001	80	8	15	.070	24.000	.060	.040	4.100	1.700	.400	5.20	3,100.0	5200.0
			18	.070	14.000	.060	.060	30.000	2.100	.200	7.50	2,800.0	4300.0
		9	9	.070	16.000	.080	.090	44.000	4.600	.400	9.70	2,400.0	4500.0
			23								18.00	900.0	7900.0
		10	1	.030	58.000	-.020	.050	1.200	30.000	.100	14.00	270.0	520.0
			10	.100	57.000	-.020	.030	.900	.300	.500	17.00	5,100.0	9500.0
			30			.100	.200	110.000	2.100	1.300	10.00	71,000.0	5900.0
		11	7	.060	52.000	.030	.050	6.700	9.000	.100	1.70	780.0	9300.0
			13	.060	22.000	.040	.050	25.000	3.100	.200	5.60	2,200.0	5100.0
	81	4	2	.120	20.000	.020	.100	24.000	2.000	.500	8.00	6,400.0	4200.0
LWM002	80	2	15										
		4	30	.030	1.700	.020	.020	9.800	.300	.080	2.10	420.0	1400.0
		5	21	.080	7.100	.060	.020	150.000	.060	.500	1.10	15,000.0	960.0
		7	31	.020	1.300	-.020	-.020	.090	.300	-.020	1.40	280.0	1100.0

LOGAN WASH
WATER QUALITY PARAMETERS
NPDES
FOR DATA SHOWN

LOC	YR	MO	DY	AMMONIA AS N (MG/L)	BOD5 (MG/L)	COD (MG/L)	OIL AND GREASE (MG/L)	PHEN (MG/L)	S (MG/L)
LWM001	80	8	15	7.40	31.00	110.0	17.00	.400	
			18	12.00	35.00	110.0	7.00	.010	
		9	9	11.00	70.00	190.0	8.00	.020	
			23	2.50		72.0	11.00	.006	
		10	1	3.50	140.00	160.0		-.001	
			10	140.00	56.00	300.0	10.00	.007	
			30	40.00	89.00	240.0	4.00	.008	-.500
		11	7	1.90	320.00	240.0	6.00	.005	-.500
			13	.70	92.00	210.0		.017	-.500
	81	4	2	5.50	100.00	130.0	12.00	.008	-.500
LWM002	80	2	15						
		4	30	14.00	60.00	50.0	5.00	.010	
		5	21	.40	100.00	250.0	14.00	.280	
		7	31	1.60	40.00	30.0	6.00	.005	

THIOCYANATE (SCN) ANALYSIS FOR VARIOUS STATIONS AT LOGAN WASH MINE SITE

LOC	YR	MO	DY	SCN (MG/L)
LWA022	80	10	22	-.100
		11	19	-.100
		12	9	-.100
	81	1	20	-.100
		2	18	-.100
LWA100	80	11	19	-.100
		12	9	-.100
	81	2	18	-.100
		4	2	.200
			9	.200
			16	-.100
			23	-.100
LWA101	80	10	22	-.100
LWA102	80	9	4	-.500
		10	2	-.500
		11	6	-.100
		12	4	-.100
LWA103	80	10	16	-.100
	81	1	29	-.100
LWA104	80	10	16	-.100
	81	1	29	-.100
LWA112	80	10	22	-.100
		11	19	-.100
		12	9	-.100
	81	4	30	-.100
LWA115	80	10	22	-.100
		11	19	-.100
		12	9	-.100
	81	1	20	-.100
		2	18	-.100
LWA121	80	9	4	-.500
LWD032	80	9	16	-.500
		12	4	-.100
LWD046	80	9	18	-.500
		12	4	-.100
LWD047	80	9	18	-.500
		12	4	-.100
LWD106	80	9	16	-.500
LWD108	80	10	22	-.100
		11	19	-.100
		12	16	-.100
	81	1	20	-.100
		2	18	.100
		4	2	.500
			9	.400
			16	.200
			23	.100
			30	.200
LWD116	80	9	16	-.500
LWD601	81	4	30	.200
LWD602	80	9	8	-.500
		10	15	.500
		11	13	-.100
		12	16	-.100
	81	2	12	-.100
LWD603	80	9	8	-.500
		10	15	-.500
		11	24	-.100
		12	16	-.100
LWD604	80	9	8	-.500
			18	-.500
		10	15	-.500
		11	13	-.100
			24	-.100
		12	16	-.100
LWD605	80	9	8	2.400
			18	1.600
		10	15	1.200
			30	.800
		11	13	.300
			24	-.100
		12	23	-.100
	81	2	12	-.100
LWD606	80	10	15	-.500
	81	2	12	.400
		3	11	.500
LWD608	80	9	18	-.500
		12	22	-.100
LWD610	80	9	8	-.500
		10	15	-.500
LWD610	80	11	13	-.100
	81	2	12	.400
LWD611	80	11	13	-.100
	81	2	12	-.100
LWM001	80	9	9	-.500
			23	-.500
		10	1	-.500
			10	-.500
			30	.500
		11	7	.500
			13	.500
LWR001	80	9	18	-.500
LWS002	80	9	4	-.500
		10	2	-.500
LWS003	80	9	4	-.500
		10	2	-.500
		11	6	-.100
		12	4	-.100
	81	1	8	-.100
		2	4	-.100
LWS004	80	9	4	-.500
		10	2	-.500
		11	6	-.100
LWS005	80	10	16	-.100
LWS006	80	10	16	-.100
LWS007	80	10	16	-.100
	81	1	29	-.100
LWS013	80	9	4	-.500
		10	2	-.500
		11	6	-.100
		12	4	-.100
	81	1	8	-.100
		2	4	-.100
LWS017	80	10	15	-.100
	81	1	29	-.100

APPENDIX F

Air Quality and Meteorology Data

AIR QUALITY AND METOROLOGICAL

MALFUNCTION COMPUTER CODES

Numerical Entry Code	Letter Code	Description
8000	TR	Trace of Precipitation
9000	CA	Calibration (calibration, system check)
9100	MT	Maintenance (changing paper, tape, charcoal)
9200	FO	Flame Out (on the GC - THC, HC, CH_4, CO)
9300	IM	Instrument Malfunction (instrument failures)
9400	PF	Power Failure (generator failure)
9450	WR	Weather Related Malfunction (instrument freezes, temperature readings below instrumental detection)
9500	RF	Recording System Failure (chart jams, runs out clock stop)
9550	NV	Not Visible (values were not within range of instrument i.e. inversion heights may exist beyond the full scale of the Acoustic Radar)
9600	LI	Local Interference (car nearby)
9650	OE	Operator Error (Field tech leaves switch in wrong position)
9700	OS	Off Scale
9750	IN	Interference (CO_2 interference on sulfur data, SO interference in oxidant readings)
9800	SE	Special Experiment
9850	OR	Out for Repair (instrument removed from site with no replacement)
9870	TS	Temporary Monitoring Shutdown due to Operations Conflict
9900	VA	Variable Wind Direction
9950	CM	Calm (no wind direction when wind speed = 0)
9980	UN	Unlimited Ceiling (reported by NWS Stations)
9999		Blank (causes a space to be printed as in the beginning of a new month before a component starts)

FREQUENCY TABLE OF WIND SPEED BY DIRECTION

10 METER LEVEL

L-W SHALE OIL PROJECT

STATION LW01 PERIOD(12/01/79 TO 2/29/80)

WIND SPEED MAX METERS/SEC		WIND DIRECTION																	
		N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	VAR	TOT
		2	1	5	8	8	5	3	3	3	3	3	3	3	5	6	2	4	
GT	11.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8. -	11.	0	0	0	1	2	0	0	0	0	0	0	0	0	0	0	0	0	
5. -	8.	0	0	2	3	3	1	0	0	0	0	0	0	0	3	3	0	0	
3. -	5.	0	0	11	22	13	9	1	2	2	1	1	1	3	21	16	0	4	1
1. -	3.	1	6	20	30	46	152	431	66	41	29	25	41	83	170	52	15	12	12
LT	1.	0	4	2	5	22	37	56	35	11	9	20	20	49	74	24	4	1	3
TOTAL		1	10	35	61	86	199	488	103	54	39	46	62	135	268	95	19	17	17
PERCENT		0.	1.	2.	4.	5.	12.	28.	6.	3.	2.	3.	4.	8.	16.	6.	1.	1.	10

0 = NO OBSERVATIONS

(06/01/81-RPI)

FREQUENCY TABLE OF WIND SPEED BY DIRECTION

10 METER LEVEL

L-W SHALE OIL PROJECT

STATION LW01 PERIOD(3/01/80 TO 5/31/80)

IND SPEED MAX ETERS/SEC		WIND DIRECTION																	
		N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	VAR	TOTAL
		2	3	5	5	6	5	4	3	8	3	3	3	5	8	9	8	3	
GT	11.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8. -	11.	0	0	0	0	0	0	0	0	1	0	0	0	0	2	2	3	0	8
5. -	8.	0	0	1	2	5	5	0	0	0	0	0	0	1	43	21	1	0	79
3. -	5.	0	1	12	14	24	12	9	3	2	4	2	1	12	101	61	4	1	263
1. -	3.	2	6	11	55	92	224	242	71	49	42	33	43	103	277	106	19	19	1394
LT	1.	0	0	1	0	12	23	31	12	8	2	5	3	11	15	5	1	14	143
TOTAL		2	7	25	71	133	264	282	86	60	48	40	47	127	438	195	28	34	1887
PERCENT		0.	0.	1.	4.	7.	14.	15.	5.	3.	3.	2.	2.	7.	23.	10.	1.	2.	100.

0 = NO OBSERVATIONS

(06/01/81-RPI)

FREQUENCY TABLE OF WIND SPEED BY DIRECTION

10 METER LEVEL

L-W SHALE OIL PROJECT

STATION LW01 PERIOD(6/01/80 TO 8/31/80)

WIND SPEED MAX METERS/SEC	WIND DIRECTION N	NNE	NE	ENE	E	ESE	SE	SSE	S	SSW	SW	WSW	W	WNW	NW	NNW	VAR	TOT
	0	5	4	4	8	5	8	4	3	2	2	2	8	8	8	3	0	
GT 11.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
8. - 11.	0	0	0	0	1	0	1	0	0	0	0	0	2	7	7	0	0	
5. - 8.	0	1	0	0	1	2	0	0	0	0	0	0	2	55	54	0	0	1
3. - 5.	0	0	2	9	29	27	7	3	2	0	0	0	10	205	73	5	0	3
1. - 3.	0	8	21	42	206	323	351	83	40	15	10	10	69	299	117	14	0	1(
LT 1.	1	0	3	1	5	11	22	14	4	1	1	5	5	18	3	1	0	
TOTAL	1	9	26	52	242	363	381	100	46	16	11	15	88	584	254	20	0	2
PERCENT	0.	0.	1.	2.	11.	16.	17.	5.	2.	1.	0.	1.	4.	26.	12.	1.	0.	1(

0 = NO OBSERVATIONS

(06/01/81-RPI)

FEBRUARY 1981

METEOROLOGIAL DATA
RELATIVE HUMIDITY
TEMPERATURE
SOLAR-RADIATION

RELATIVE HUMIDITY
PERCENT

LOGAN WASH
STATION LW02
FEB 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE	P
1	54	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	
2	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
3	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	30	28	24	23	20	19	18	19	( )	
4	19	20	20	20	20	24	24	26	27	33	37	40	40	41	43	42	43	44	44	46	50	52	58	66	37	
5	66	63	63	58	59	49	47	43	40	41	41	40	38	35	41	47	46	44	46	52	54	58	56	58	49	
6	56	55	52	52	54	56	55	51	50	51	52	51	51	50	50	49	46	43	48	48	48	50	50	49	51	
7	49	50	51	57	60	67	68	58	58	55	61	63	62	56	56	54	51	48	49	51	51	50	50	51	55	
8	51	51	51	53	55	57	60	61	58	55	54	53	50	52	49	46	43	42	42	44	46	47	48	48	51	
9	48	48	49	51	53	56	65	73	95	97	97	97	96	96	97	97	97	97	97	97	96	96	97	97	83	
10	97	97	96	96	95	94	92	90	90	89	89	(RF)	(RF)	(RF)	84	82	42	33	30	(RF)	(RF)	(RF)	(RF)	(RF)	( )	
11	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	30	30	31	37	79	94	93	93	93	93	93	( )	
12	92	78	72	72	66	76	80	70	68	64	62	63	65	67	64	58	52	51	50	54	53	52	57	56	64	
13	55	59	58	58	55	57	60	59	57	50	47	43	41	42	43	42	36	33	36	41	39	39	38	40	47	
14	39	38	38	35	33	33	32	31	30	28	27	25	25	26	26	26	26	28	28	28	28	28	29	33	30	
15	36	38	52	61	64	64	64	67	67	66	68	61	59	49	43	41	44	45	44	41	40	44	42	45	52	
16	50	51	50	52	50	48	49	49	48	46	43	43	40	40	41	40	42	42	44	45	48	48	48	48	46	
17	48	49	50	50	50	49	49	49	49	52	55	54	55	50	57	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	
18	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	(
19	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	(
20	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	(
21	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	(
22	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	(
23	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	13	14	13	13	13	( )	
24	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	25	23	21	16	15	25	13	13	42	45	45	45	23	
25	15	15	15	15	16	16	18	16	16	16	17	16	16	16	16	17	22	28	35	41	(RF)	(RF)	(RF)	(RF)	70	
26	43	41	39	37	37	38	40	46	58	99	97	95	95	96	95	95	95	94	94	(RF)	(RF)	(RF)	(RF)	(RF)	( )	
27	91	87	81	85	84	83	79	80	77	71	68	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
28	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	
AV	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	
PK	97	97	96	96	95	94	92	90	95	99	97	97	96	96	97	97	97	97	97	97	96	96	97	97		

TEMPERATURE @2M
DEGREE C

LOGAN WASH
STATION LW02
FEB 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE	PEAK
1	2	-11	-11	-12	-12	-12	-12	-13	-13	-13	-13	-14	-14	-14	-14	-14	-14	-14	-14	-14	-14	-13	-13	-11	-12	2
2	-11	-9	-8	-6	-7	-7	-8	-9	-10	-9	-9	-9	-9	-10	-9	-9	-9	-9	-9	-9	-9	-8	-9	-9	-9	-6
3	-8	-6	-4	-2	-2	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	-3	-2	-1	-3	-5	-5	-5	(RF)	( )	-1
4	(RF)	(RF)	(RF)	(RF)	-6	-6	-6	-6	-6	-6	-6	-4	-4	-3	-2	-2	-2	-2	-2	-4	-6	-6	-7	-7	-4	-2
5	-7	-7	-7	-8	-8	-9	-9	-8	-8	-8	-6	-5	-2	-2	-3	-4	-3	-3	-4	-6	-6	-7	-7	-7	-6	-2
6	-7	-6	-7	-7	-7	-7	-6	-6	-6	-6	-6	-6	-5	-4	-3	-2	-1	-3	-3	-4	-4	-5	-6	-6	-5	-1
7	-7	-7	-7	-8	-8	-9	-9	-9	-9	-9	-9	-8	-7	-6	-4	-3	-3	-4	-6	-7	-7	-7	-7	-7	-7	-3
8	-7	-7	-7	-8	-8	-8	-9	-9	-8	-8	-8	-6	-7	-6	-4	-4	-4	-4	-4	-5	-6	-5	-5	-4	-6	-4
9	-4	-4	-4	-5	-5	-5	-6	-7	-7	-7	-7	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-4
0	-6	-6	-6	-6	-7	-8	-10	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	-6
1	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	-9	-8	-9	-9	-10	-11	-10	-11	-10	-10	-10	-10	( )	-8
2	-10	-10	-10	-10	-10	-10	-11	-10	-8	-7	-6	-6	-5	-4	-3	-1	-1	-3	-5	-6	-6	-6	-6	-6	-7	-1
3	-6	-6	-6	-6	-6	-6	-6	-6	-4	-3	-1	-1	-1	0	1	1	1	-1	-2	-2	-2	-2	-2	-2	-3	1
4	-2	-2	-3	-1	-1	-1	-1	-1	-1	0	2	1	2	2	2	2	2	1	1	1	1	-1	-1	-1	0	2
5	-1	-1	-2	-3	-3	-3	-3	-3	-2	-2	0	1	2	3	3	2	0	-1	-1	-2	-2	-2	-2	-2	-1	3
6	-2	-2	-2	-2	-2	-3	-3	-3	-1	0	2	3	3	4	4	3	3	2	1	1	1	0	0	0	0	4
7	0	0	0	0	0	0	0	0	-1	-1	-1	-1	1	2	2	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	2
8	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	( )
9	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	( )
0	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	( )
1	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	( )
2	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	( )
3	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	( )	( )
4	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	(OE)	7	7	8	7	6	6	3	3	2	2	2	1	( )	8
5	2	2	2	2	1	1	1	3	3	6	7	7	7	7	7	6	4	3	2	2	2	2	2	2	3	7
6	2	2	2	2	2	1	0	0	-1	-3	-4	-4	-4	-3	-3	-4	-6	-6	-6	-6	-6	-7	-7	-7	-3	2
7	-7	-7	-7	-7	-7	-7	-7	-7	-5	-4	-2	-2	-1	1	1	1	0	-1	-3	-3	-3	-4	-4	-4	-4	1
8	-4	-4	-4	-4	-4	-4	-4	-3	-1	1	2	2	2	3	3	2	1	0	-1	-1	-2	-1	-1	-2	-1	3
V	-4	-5	-5	-5	-5	-5	-6	-5	-5	-4	-4	-3	-2	-2	-2	-2	-2	-3	-3	-4	-4	-4	-5	-5	-4	
K	2	2	2	2	2	1	1	3	3	6	7	7	7	7	8	7	6	6	3	3	2	2	2	2		7

SOLAR RADIATION
LANGLEYS

LOGAN WASH
STATION LW02
FEB 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	TL	PE
1	0	0	0	0	0	0	0	4	12	35	43	47	47	27	47	35	12	0	0	0	0	0	0	0	306	
2	0	0	0	0	0	0	0	4	23	39	58	70	66	58	58	50	39	19	0	0	0	0	0	0	485	
3	0	0	0	0	0	0	0	0	12	31	47	58	62	58	50	43	19	0	0	0	0	0	0	0	380	
4	0	0	0	0	0	0	0	4	12	39	39	62	66	62	54	39	19	4	0	0	0	0	0	0	399	
5	0	0	0	0	0	0	0	4	27	43	58	62	62	50	50	39	12	0	0	0	0	0	0	0	407	
6	0	0	0	0	0	0	0	4	19	27	43	50	58	66	39	19	16	4	0	0	0	0	0	0	345	
7	0	0	0	0	0	0	0	8	27	39	62	66	66	62	54	43	16	4	0	0	0	0	0	0	446	
8	0	0	0	0	0	0	0	12	16	43	31	31	58	58	47	39	16	4	0	0	0	0	0	0	353	
9	0	0	0	0	0	0	0	4	16	19	23	27	31	31	19	12	4	0	0	0	0	0	0	0	186	
10	0	0	0	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	
11	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	50	19	19	16	4	0	0	0	0	0	0	( )	
12	0	0	0	0	0	0	0	4	16	35	47	58	62	58	54	43	27	8	0	0	0	0	0	0	411	
13	0	0	0	0	0	0	0	4	19	35	50	58	66	62	58	47	31	8	0	0	0	0	0	0	438	
14	0	0	0	0	0	0	0	4	16	31	54	39	35	47	39	31	19	8	0	0	0	0	0	0	322	
15	0	0	0	0	0	0	0	4	19	23	58	58	50	54	50	35	12	4	0	0	0	0	0	0	368	
16	0	0	0	0	0	0	0	4	12	27	39	54	62	58	58	50	27	16	0	0	0	0	0	0	407	
17	0	0	0	0	0	0	0	0	8	12	19	31	47	50	35	43	31	12	0	0	0	0	0	0	287	
18	0	0	0	0	0	0	0	4	16	35	50	54	62	54	47	31	23	8	0	0	0	0	0	0	384	
19	0	0	0	0	0	0	0	4	16	35	39	39	66	47	47	43	19	8	0	0	0	0	0	0	361	
20	0	0	0	0	0	0	0	4	16	12	8	12	19	31	19	12	12	4	0	0	0	0	0	0	147	
21	0	0	0	0	0	0	0	8	39	50	66	58	43	66	50	43	16	12	0	0	0	0	0	0	450	
22	0	0	0	0	0	0	0	4	23	39	54	62	66	66	62	50	35	19	0	0	0	0	0	0	481	
23	0	0	0	0	0	0	0	4	19	39	50	62	66	66	62	54	43	27	4	0	0	0	0	0	496	
24	0	0	0	0	0	0	0	4	23	43	54	66	66	66	62	50	35	12	0	0	0	0	0	0	481	
25	0	0	0	0	0	0	0	4	23	43	54	62	62	39	50	47	31	8	0	0	0	0	0	0	423	
26	0	0	0	0	0	0	0	0	0	4	8	8	16	27	8	8	4	0	0	0	0	0	0	0	82	
27	0	0	0	0	0	0	4	23	39	54	62	70	78	70	47	31	23	4	0	0	0	0	0	0	504	
28	0	0	0	0	0	0	0	16	35	50	62	66	62	39	47	39	16	4	0	0	0	0	0	0	434	
TL	0	0	0	0	0	0	4	136	500	880	1178	1329	1442	1422	1233	992	570	198	4	0	0	0	0	0	9780	
PK	0	0	0	0	0	0	4	23	39	54	66	70	78	70	62	54	43	27	4	0	0	0	0	0		

RELATIVE HUMIDITY
PERCENT

LOGAN WASH
STATION LW04
FEB 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE	PEAK
1	84	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	84
2	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
3	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	31	48	67	74	76	78	82	84	( )	84
4	84	85	87	88	90	90	90	91	91	87	56	44	35	31	30	29	30	38	55	61	55	54	58	59	63	91
5	62	67	69	75	76	83	88	90	87	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	90
6	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
7	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
8	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
9	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
10	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	32	31	28	27	25	23	24	34	37	42	43	43	43	47	( )	47
11	51	53	61	62	66	72	75	77	77	71	56	48	41	35	35	33	33	35	53	63	77	75	79	83	59	83
12	84	86	85	89	90	93	95	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	95
13	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
14	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
15	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
16	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
17	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	36	32	27	27	28	45	52	54	56	58	60	59	75	56	93	93	96	60	96
18	88	86	86	72	81	85	90	93	75	54	41	36	29	24	20	20	21	34	48	57	64	63	67	63	56	93
19	79	86	90	91	94	95	96	96	85	56	46	36	30	26	24	21	24	33	49	54	58	60	61	63	61	96
20	69	72	75	81	81	82	83	84	85	58	30	37	55	65	67	80	60	52	64	56	50	42	42	45	61	84
21	48	48	50	51	51	59	63	60	57	47	41	37	31	26	24	23	21	25	35	54	60	65	67	66	48	67
22	70	72	77	78	81	84	88	90	81	55	43	33	27	23	21	20	20	21	38	49	54	58	68	72	53	90
23	75	78	82	84	85	90	92	92	88	59	40	32	27	20	18	17	16	17	26	41	44	48	54	61	54	92
24	65	73	78	79	83	90	92	94	80	54	40	31	17	12	8	6	6	6	14	21	35	46	53	52	47	94
25	53	56	63	67	71	75	78	82	81	63	35	25	13	10	9	9	9	14	17	22	31	44	50	64	44	82
26	70	75	80	83	84	85	88	83	79	68	87	95	98	86	58	84	85	92	94	96	99	99	99	99	85	99
27	99	99	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	99
28	78	83	85	89	90	90	91	92	91	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	92
AV	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	
MX	99	99	90	91	94	95	96	96	91	87	87	95	98	86	67	80	85	92	94	96	99	99	99	99		99

NO REC: STATUS MK 1 2 281

TEMPERATURE
DEGREE C

LOGAN WASH
STATION LW04
FEB 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE	P
1	-11	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	
2	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
3	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	6	6	-1	-2	-3	-4	-6	-7	( )	
4	-8	-8	-9	-11	-11	-12	-12	-11	-11	-10	-4	-1	2	4	6	7	7	7	(RF)	(RF)	(RF)	0	-1	-2	-4	
5	-3	-4	-6	-7	-8	-10	-11	-12	-10	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	
6	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
7	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
8	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
9	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	-7	-6	-6	-6	-6	-5	-5	-9	-10	-11	-12	-13	-8	
10	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	-7	-9	-6	-6	-6	-6	-5	-5	-3	-3	-4	-4	-4	-5	
11	-14	-14	-16	-16	-16	-15	-15	-14	-14	-13	-10	-9	-6	-4	-4	-4	-2	-2	-3	-3	-4	-4	-4	-4	( )	
12	-4	-4	-5	-6	-7	-8	-8	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	
13	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
14	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
15	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
16	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
17	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	8	11	12	13	13	9	6	7	7	7	7	8	9	
18	4	3	3	2	2	1	-1	-1	1	3	8	9	12	13	14	14	14	13	9	6	4	4	4	5	7	
19	1	1	-1	-1	-2	-2	-3	-2	0	4	7	9	11	13	14	15	15	14	10	12	12	12	12	12	8	
20	-1	1	3	2	2	2	1	1	4	(RF)	8	7	9	4	4	2	3	3	2	2	2	1	1	1	3	
21	-1	-1	-1	-1	-1	-1	-2	-2	-1	1	2	3	4	4	6	6	7	7	3	-1	-2	-2	-3	-3	1	
22	-4	-4	-6	-6	-7	-7	-8	-8	-4	-1	2	4	6	7	9	10	11	11	8	2	2	1	-1	-2	2	
23	-3	-3	-4	-4	-6	-6	-6	-6	-3	1	4	7	9	12	13	14	15	15	13	5	4	3	2	1	4	
24	-2	-2	-2	-3	-4	-4	-6	-6	-3	1	5	9	13	16	17	18	18	17	(RF)	(RF)	4	3	3	3	6	
25	-1	-1	-2	-1	-2	-3	-4	-4	-4	-1	6	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	4	3	1	4	
26	1	1	-2	-2	-2	-1	-1	-1	0	3	5	4	3	4	8	8	6	4	3	3	2	2	1	1	2	
27	1	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	4	3	1	2	( )	
28	1	0	-1	-2	-2	-3	-3	-3	-2	1	4	6	8	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	4	4	1	
AV	-2	-2	-3	-4	-5	-5	-6	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	1	1	0	1	
PK	11	10	3	2	2	2	1	1	4	4	8	9	13	16	17	18	18	17	13	12	12	12	12	12		

MARCH 1981

METEOROLOGICAL DATA
RELATIVE HUMIDITY
TEMPERATURE
SOLAR RADIATION

RELATIVE HUMIDITY
PERCENT

LOGAN WASH
STATION LW02
MAR 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE	PE
1	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
2	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
3	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
4	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
5	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	53	53	53	58	67	64	65	62	65	( )	
6	70	95	97	96	96	97	96	98	98	97	96	93	97	96	95	95	95	95	95	95	95	95	95	95	95	
7	95	94	94	94	94	94	94	94	94	94	95	95	95	95	95	96	96	96	96	95	95	95	95	94	95	
8	94	94	92	91	92	92	94	92	93	81	74	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	
9	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
10	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	50	42	40	53	46	52	57	58	58	57	57	57	( )	
11	56	57	56	56	57	58	58	56	55	56	56	59	56	51	44	47	53	73	80	90	88	94	98	99	65	
12	99	97	97	96	96	96	96	96	96	96	96	96	97	97	97	88	55	50	54	62	76	69	73	76	85	
13	77	86	88	88	84	89	93	92	83	70	63	63	57	47	44	49	48	47	64	63	69	68	66	65	69	
14	70	77	74	74	80	79	76	76	70	64	58	52	45	43	46	52	50	46	51	51	50	50	58	61	61	
15	66	68	84	88	80	85	89	96	95	89	86	74	60	57	49	40	61	47	46	52	52	53	53	56	68	
16	61	65	63	64	65	65	66	68	66	65	60	55	52	50	45	47	46	48	58	93	75	73	80	100	64	)
17	100	99	99	95	93	90	91	91	90	89	88	(RF)	(RF)	(RF)	(RF)	86	67	71	69	75	74	65	70	71	84	1
18	71	80	86	92	93	95	96	89	89	85	75	73	72	68	65	59	54	51	55	50	48	48	49	47	70	
19	46	45	46	48	49	48	46	45	43	36	34	38	37	35	31	29	31	35	38	51	60	54	54	48	43	
20	46	42	41	40	41	51	50	49	47	60	76	81	91	98	98	98	98	89	72	64	69	72	80	90	68	
21	93	97	96	96	95	95	95	95	95	95	95	95	95	77	76	73	74	95	94	92	88	85	84	79	90	
22	76	75	72	73	74	80	75	77	76	75	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	
23	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
24	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	70	67	83	79	80	84	80	75	70	66	( )	
25	64	67	60	85	93	90	85	72	54	42	44	40	30	30	28	28	29	29	28	28	28	27	27	26	47	
26	26	26	26	27	30	33	35	36	36	34	33	30	29	30	29	30	35	52	56	58	46	85	97	97	42	
27	98	98	97	97	96	96	95	95	95	95	77	63	58	54	54	55	60	66	75	71	76	82	95	97	81	
28	96	96	96	96	96	96	96	96	96	96	92	84	98	93	97	97	94	95	96	97	97	96	96	96	95	
29	96	96	95	95	96	96	95	93	87	86	85	80	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	
30	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
31	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(AF)	(RF)	77	75	73	67	67	67	65	62	61	( )	
AV	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	72	
PK	100	99	99	97	96	97	96	98	98	97	96	96	98	98	98	98	98	96	96	97	97	96	98	100		1

TEMPERATURE @2M
DEGREE C

LOGAN WASH
STATION LW02
MAR 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE	PEAK
1	-11	-2	-2	-2	-2	-3	-3	-3	-1	-1	1	2	1	0	0	-1	-2	-3	-3	-3	-3	-3	-4	-4	-2	2
2	-4	-4	-4	-4	-4	-4	-4	-3	-2	0	-1	0	2	1	-3	-4	-3	-3	-4	-4	-4	-4	-4	-4	-3	2
3	-4	-4	-4	-5	-6	-6	-6	-7	-7	-6	-6	-4	-4	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	-4
4	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
5	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	4	5	5	4	1	1	0	0	0	-1	( )	5
6	-2	-2	-2	-2	-3	-3	-3	-2	-2	-2	-2	-2	-3	-4	-4	-4	-4	-4	-4	-4	-4	-4	-4	-4	-3	-2
7	-4	-5	-5	-5	-5	-5	-5	-4	-3	-2	-2	-2	-2	-2	-2	-2	-3	-3	-4	-4	-5	-5	-5	-5	-4	-2
8	-5	-5	-6	-6	-6	-6	-6	-5	-3	-2	-1	0	-1	-1	-1	0	-1	-1	-3	-3	-3	-3	-4	-3	-3	0
9	-4	-4	-4	-4	-4	-4	-5	-4	-4	-2	-2	2	3	4	4	4	3	2	0	-1	-2	-2	-2	-2	-1	4
10	-3	-3	-3	-3	-3	-3	-4	-4	-3	-2	0	3	4	3	2	3	3	1	0	0	-1	-1	-1	-1	-1	4
11	-1	-2	-2	-2	-3	-3	-3	-3	-3	-2	-2	-2	-1	1	4	3	1	-1	-1	-1	-2	-2	-2	-2	-1	4
12	-2	-2	-3	-3	-3	-3	-3	-3	-3	-3	-2	-2	-2	-2	-1	2	4	3	-1	-1	-2	-2	-3	-3	-2	4
13	-3	-4	-3	-3	-3	-4	-4	-4	-2	-1	2	3	3	3	2	3	4	2	0	-1	-1	-1	-2	-2	-1	4
14	-3	-3	-3	-3	-3	-3	-3	-3	-2	-1	0	3	5	4	2	4	3	2	1	-1	-1	0	-1	-1	0	5
15	-1	-2	-2	-2	-2	-2	-2	-2	-1	0	2	4	6	7	7	4	4	5	3	2	2	2	1	1	2	7
16	1	1	1	0	0	0	0	1	1	2	3	4	6	6	4	5	4	3	1	1	1	1	2	2	2	6
17	-2	-2	-2	-4	-6	-6	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	-2	-2	-3	-4	-4	-4	-4	-4	-4	( )	-2
18	-4	-4	-5	-5	-6	-6	-7	-6	-6	-4	-1	1	-1	1	-1	1	1	0	-1	-2	-2	-2	-2	-2	-3	1
19	-2	-2	-2	-2	-2	-2	-1	-1	-1	2	4	4	4	5	7	6	5	4	3	3	3	3	3	3	2	7
20	3	3	4	4	3	3	3	3	3	2	1	0	-1	0	0	0	0	-1	-1	-1	-1	-1	-1	-1	-1	4
21	-3	-3	-4	-4	-4	-4	-4	-4	-4	-4	-4	-3	-2	-2	-1	-1	-1	-1	-2	-2	-2	-2	-2	-2	-3	-1
22	-2	-2	-2	-1	-2	-2	-2	-1	0	1	2	6	7	8	4	8	6	4	3	3	2	2	2	2	2	8
23	2	2	2	2	2	2	2	2	2	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	2
24	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	1	2	1	1	0	0	-1	-1	-1	-1	-1	-1	( )	2
25	-1	-1	-1	-2	-2	-2	-2	-1	3	5	7	8	8	7	8	7	6	6	6	6	6	6	6	6	4	8
26	6	6	6	5	5	6	7	8	9	10	10	11	9	9	9	8	8	6	6	7	3	1	1	1	6	11
27	-2	-2	-2	-3	-4	-4	-4	-4	-4	-3	-2	0	1	2	1	1	0	-1	-2	-2	-2	-2	-3	-3	-2	2
28	-3	-3	-4	-4	-3	-3	-3	-2	-2	-2	-3	-2	-2	-3	-3	-3	-3	-3	-3	-4	-4	-5	-5	-5	-3	-2
29	-5	-4	-4	-4	-4	-4	-3	-2	-1	1	1	2	2	3	3	3	2	2	2	2	2	2	2	2	0	3
30	2	2	2	1	1	1	-2	-2	-2	-3	-4	-2	-4	-5	-6	-6	-6	-6	-7	-7	-7	-7	-7	-7	-3	2
31	-7	-7	-7	-7	-7	-7	-7	-6	-4	-4	-2	-1	-1	(MT)	(MT)	-2	-2	-2	-3	-3	-3	-3	-2	-2	-4	-1
AV	-2	-2	-2	-2	-3	-3	-3	-2	-2	-1	0	1	1	2	2	2	1	0	-1	-1	-1	-1	-2	-2	-1	
PK	6	6	6	5	5	6	7	8	9	10	10	11	9	9	9	8	8	6	6	7	6	6	6	6		11

SOLAR RADIATION
LANGLEYS

LOGAN WASH
STATION LW02
MAR 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	TL	PE
1	0	0	0	0	0	0	0	12	27	43	62	50	47	39	27	19	8	4	0	0	0	0	0	0	337	
2	0	0	0	0	0	0	0	8	8	23	12	19	43	23	8	8	4	0	0	0	0	0	0	0	155	
3	0	0	0	0	0	0	0	8	16	27	23	31	23	23	54	19	19	4	0	0	0	0	0	0	248	
4	0	0	0	0	0	0	0	4	8	12	47	66	50	39	39	23	12	0	0	0	0	0	0	0	299	
5	0	0	0	0	0	0	0	12	27	39	58	62	39	66	54	39	27	8	0	0	0	0	0	0	430	
6	0	0	0	0	0	0	0	0	4	23	27	27	12	12	12	16	4	0	0	0	0	0	0	0	136	
7	0	0	0	0	0	0	0	8	12	35	43	47	43	50	35	12	12	0	0	0	0	0	0	0	294	
8	0	0	0	0	0	0	4	23	35	54	74	35	23	50	62	47	27	8	0	0	0	0	0	0	442	
9	0	0	0	0	0	0	8	19	35	43	62	70	74	74	66	54	39	27	0	0	0	0	0	0	570	
10	0	0	0	0	0	0	0	8	27	43	58	70	62	23	39	31	4	4	0	0	0	0	0	0	368	
11	0	0	0	0	0	0	0	8	8	23	16	31	43	50	23	16	12	4	0	0	0	0	0	0	233	
12	0	0	0	0	0	0	0	16	23	16	16	19	27	58	58	47	43	4	0	0	0	0	0	0	325	
13	0	0	0	0	0	0	12	27	47	58	62	54	66	19	47	43	23	4	0	0	0	0	0	0	461	
14	0	0	0	0	0	0	12	27	47	47	74	39	27	19	39	16	4	0	0	0	0	0	0	0	349	
15	0	0	0	0	0	0	12	27	43	50	70	85	74	70	27	43	35	4	0	0	0	0	0	0	539	
16	0	0	0	0	0	0	8	19	39	50	58	62	58	54	39	31	8	4	0	0	0	0	0	0	430	
17	0	0	0	0	0	0	0	8	35	50	50	39	58	39	43	47	39	16	0	0	0	0	0	0	423	
18	0	0	0	0	0	0	4	12	43	62	43	50	43	35	23	50	35	12	0	0	0	0	0	0	411	
19	0	0	0	0	0	0	0	19	43	58	58	47	54	62	47	43	8	4	0	0	0	0	0	0	442	
20	0	0	0	0	0	0	4	4	4	4	12	8	12	19	16	8	23	4	0	0	0	0	0	0	116	
21	0	0	0	0	0	0	4	12	19	31	27	27	27	23	27	16	8	4	0	0	0	0	0	0	225	
22	0	0	0	0	0	0	12	39	50	62	66	70	78	23	47	47	12	8	0	0	0	0	0	0	512	
23	0	0	0	0	0	0	8	23	47	62	66	66	58	39	66	66	54	23	0	0	0	0	0	0	578	
24	0	0	0	0	0	0	0	12	23	39	27	58	(MT)	(MT)	58	47	39	19	0	0	0	0	0	0	322	
25	0	0	0	0	0	0	8	23	43	58	70	74	70	47	39	43	12	4	0	0	0	0	0	0	488	
26	0	0	0	0	0	0	4	27	47	58	66	66	58	19	27	12	12	4	0	0	0	0	0	0	399	
27	0	0	0	0	0	0	0	4	4	16	12	43	47	66	50	58	31	19	8	0	0	0	0	0	357	
28	0	0	0	0	0	0	8	16	27	27	31	54	50	27	23	16	12	4	0	0	0	0	0	0	295	
29	0	0	0	0	0	4	8	23	50	62	50	70	78	50	31	39	19	12	0	0	0	0	0	0	496	
30	0	0	0	0	0	0	4	4	8	12	23	23	58	19	19	16	12	4	0	0	0	0	0	0	202	
31	0	0	0	0	0	0	4	19	35	47	70	81	78	(MT)	(MT)	58	47	35	4	0	0	0	0	0	477	
TL	0	0	0	0	0	4	120	469	880	1232	1430	1543	1476	1140	1144	1023	640	245	12	0	0	0	0	0	****	
PK	0	0	0	0	0	4	12	39	50	62	74	85	78	74	66	66	54	35	8	0	0	0	0	0		

RELATIVE HUMIDITY
PERCENT

LOGAN WASH
STATION LW04
MAR 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE	PEAK
1	49	77	78	82	85	91	93	91	87	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	79	89	89	( )	93
2	90	92	94	95	96	96	96	97	97	90	83	(RF)	(RF)	(RF)	(RF)	(RF)	91	93	98	98	98	99	99	99	95	99
3	99	100	99	99	99	99	99	99	(MT)	(MT)	(MT)	(MT)	66	63	49	(RF)	73	71	82	85	91	95	95	95	87	100
4	96	96	96	96	97	97	97	97	96	90	69	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	84	(RF)	( )	97
5	81	82	84	88	89	89	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	89
6	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
7	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
8	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
9	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
10	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	38	32	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	50	55	60	60	64	64	( )	64
11	72	74	75	82	85	84	85	82	81	79	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	50	62	70	72	77	81	81	( )	85
12	86	84	88	93	95	96	95	96	95	85	55	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	58	66	74	( )	98
13	80	83	84	85	86	88	91	84	82	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	66	70	( )	91
14	75	80	84	85	89	90	93	95	95	71	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	74	75	( )	95
15	80	85	85	87	87	89	93	93	93	72	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	93
16	75	79	84	86	88	91	95	96	94	76	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	92	( )	96
17	96	97	98	95	94	96	81	88	92	76	(MT)	(MT)	36	39	30	28	34	44	46	54	58	60	63	62	67	98
18	61	67	81	87	89	91	76	53	39	35	30	24	23	23	22	22	21	38	40	52	63	66	64	60	51	91
19	62	68	69	70	75	78	65	(RF)	(RF)	(RF)	(RF)	13	12	12	13	14	26	29	37	45	51	60	70	72	47	78
20	73	75	70	70	66	67	64	59	51	60	71	65	59	42	47	38	36	39	42	45	48	52	64	74	58	75
21	76	86	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	86
22	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	( )
23	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	( )
24	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	50	47	53	68	75	83	85	85	( )	85
25	87	89	93	96	98	99	99	99	90	55	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	99
26	(RF)	(RF)	(RF)	(RF)	60	64	70	73	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	73
27	(RF)	94	98	93	97	70	65	60	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	68	73	70	( )	98
28	75	98	98	98	98	98	98	98	98	98	97	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	78	( )	98
29	84	84	79	77	77	77	82	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	83	( )	84
30	88	93	93	85	(RF)	(RF)	(RF)	(RF)	90	96	98	98	100	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	100
31	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	75	74	77	( )	77
AV	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	
MX	99	100	99	99	99	99	99	99	98	98	98	98	100	63	49	38	91	93	98	98	98	99	99	99		100

NO REC: STATUS NR 1 2 381

TEMPERATURE
DEGREE C

LOGAN WASH
STATION LW04
MAR 1981
OCCIDENTIAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE
1	1	2	2	2	1	-1	-1	-1	0	2	6	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	0	4	2	1	2
2	1	0	-1	-1	-1	-1	-1	-1	0	2	3	4	6	8	8	6	4	3	3	3	3	3	2	2	( )
3	2	2	2	2	2	2	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
4	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
5	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )
6	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )
7	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )
8	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )
9	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	12	11	9	7	6	6	4	3	8
10	2	2	1	-1	-1	-1	-1	-1	0	1	3	6	8	9	12	14	11	12	11	9	8	6	6	5	4
11	4	4	4	4	3	3	2	3	3	4	8	10	9	11	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	5	3	4
12	0	0	0	0	-1	-2	-2	-3	-2	2	6	9	11	12	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	5	3	2	4
13	0	-1	-1	-2	-2	-2	-3	-3	-2	2	5	8	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	3	2	1	4
14	0	-1	-1	-1	-2	-2	-3	-3	-2	2	5	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	4
15	(RF)	(RF)	-1	-1	-2	-2	-3	-3	-2	2	5	9	12	(RF)	(RF)	(RF)	(RF)	(RF)	10	9	9	8	6	4	4
16	4	4	3	2	2	2	3	3	3	3	6	9	12	14	(MT)	6	7	7	5	3	3	2	2	2	4
17	2	2	2	2	2	2	3	3	3	3	7	9	10	12	14	14	13	12	11	10	9	8	7	5	6
18	1	1	1	1	2	2	3	3	3	3	7	9	10	12	14	14	13	12	11	10	9	8	7	5	6
19	3	3	3	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
20	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
21	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
22	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
23	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
24	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	9	10	10	8	8	6	2	2	1	1	( )
25	-1	-1	-2	-3	-4	-5	-6	-6	-3	1	5	7	10	12	12	14	16	14	13	9	6	5	4	4	6
26	4	4	4	3	2	1	0	-1	2	10	14	17	18	17	17	18	18	17	16	12	10	9	8	7	10
27	3	4	2	2	2	2	2	2	2	3	4	5	8	8	9	9	9	8	8	3	2	1	1	1	4
28	-1	-1	-1	-1	-1	-1	-1	-1	-1	2	4	5	3	4	4	4	4	5	4	3	4	3	2	1	2
29	-1	-1	-1	-1	-1	-1	-2	-1	-1	1	4	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)					
30	-2	-2	-1	-1	-1	-1	-2	-1	-1	1	1	1	0	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	2
31	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	6	7	7	8	9	9	8	3	2	1	1	0	5
AV	1	1	1	0	0	0	-1	-1	1	3	5	7	8	( )	( )	( )	( )	( )	( )	( )	5	4	3	2	4
PK	4	4	4	4	4	6	7	7	3	10	14	17	18	17	17	18	18	17	16	12	13	13	11	7	

APRIL 1981

METEOROLOGIAL DATA
RELATIVE HUMIDITY
TEMPERATURE
SOLAR-RADIATION

RELATIVE HUMIDITY
PERCENT

LOGAN WASH
STATION LW02
APR 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE	PE
1	(RF)	59	56	50	45	45	42	41	36	34	30	34	33	34	29	27	26	27	25	25	26	26	29	29	35	
2	28	26	26	25	26	26	27	27	27	29	29	30	25	24	25	22	23	27	30	31	33	33	39	70	30	
3	81	99	99	98	96	96	96	96	96	95	95	95	95	95	95	95	95	95	95	94	93	92	89	90	94	
4	89	85	78	81	78	81	81	82	81	81	80	78	75	76	76	74	75	73	67	65	64	(RF)	(RF)	(RF)	77	
5	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
6	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
7	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	36	41	50	51	50	78	91	75	62	80	88	( )	
8	94	93	93	72	80	82	84	83	89	81	82	76	63	60	53	50	43	40	39	40	40	41	41	44	65	
9	46	47	50	50	45	41	38	35	35	38	36	33	31	29	28	27	27	27	27	27	27	27	26	25	34	
10	26	26	26	27	28	28	28	28	29	29	27	26	22	19	17	16	16	12	13	13	13	13	14	16	21	
11	17	17	19	22	24	25	25	25	25	25	25	24	23	23	21	19	17	17	20	21	23	23	24	25	22	
12	23	23	25	25	25	25	25	25	25	24	24	24	24	25	25	25	25	26	27	27	(IM)	(IM)	(IM)	(IM)	25	
13	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	(
14	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	33	31	35	33	34	40	46	55	69	81	78	( )	
15	81	80	83	94	97	98	98	97	97	96	89	88	81	85	80	71	80	62	63	66	93	90	89	86	85	
16	82	79	77	76	79	79	80	76	75	74	74	72	72	61	52	44	36	29	28	28	30	33	37	43	59	
17	48	50	50	50	48	47	46	45	42	39	38	37	35	32	29	27	26	27	27	29	31	32	32	32	37	
18	32	32	36	38	40	40	41	40	39	38	35	29	26	26	22	20	19	24	41	42	50	90	92	97	41	
19	97	96	93	94	95	91	90	86	81	(RF)	(RF)	(MT)	29	28	27	30	33	39	40	44	55	63	85	(RF)	65	
20	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
21	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
22	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
23	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
24	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
25	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	(
26	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	56	71	( )	
27	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	19	23	27	29	31	45	
28	72	74	74	73	75	84	81	74	66	55	45	37	29	25	21	18	14	12	13	23	25	21	22	25	31	
29	33	35	37	39	39	40	43	42	46	45	39	34	29	25	23	21	21	21	22	23	25	21	22	25	32	
30	26	26	27	27	33	36	38	39	38	38	38	35	30	30	31	31	28	30	29	28	32	35	36	36	32	
AV	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	47	
PK	97	99	99	98	97	98	98	97	97	96	95	95	95	95	95	95	95	95	95	94	93	92	92	97		

TEMPERATURE @2M
DEGREE C

LOGAN WASH
STATION LW02
APR 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE	PEAK
1	-2	-2	-2	-2	-1	-1	-1	1	1	2	3	4	5	6	6	6	6	6	5	4	4	4	4	4	3	6
2	4	4	4	4	4	3	3	4	6	7	8	8	9	9	9	8	7	7	6	5	5	4	3	1	6	9
3	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
4	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
5	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
6	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
7	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	4	3	2	3	1	-2	-2	-2	-4	-4	-4	( )	4
8	-5	-6	-6	-6	-6	-4	-4	-3	-2	-1	-1	1	1	1	1	2	2	1	1	1	1	1	1	1	-1	2
9	1	0	1	1	1	2	3	4	4	7	9	9	9	10	10	10	10	9	8	8	7	7	8	7	6	10
10	7	7	6	6	6	6	7	7	9	10	11	12	12	13	12	11	11	10	9	8	8	8	8	7	9	13
11	7	6	6	5	4	5	7	7	9	9	11	11	9	9	10	11	10	9	8	7	7	6	6	6	8	11
12	5	4	4	3	4	6	7	8	10	10	10	9	9	7	6	6	6	6	6	(IM)	(IM)	(IM)	(IM)	(IM)	7	10
13	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
14	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	17	14	16	15	13	11	10	8	8	7	7	( )	17
15	7	6	6	4	4	3	3	3	3	3	4	5	6	4	9	7	8	8	8	3	3	3	3	3	5	9
16	3	4	4	3	3	3	3	4	6	7	8	9	10	12	13	12	13	13	12	11	10	10	9	9	8	13
17	9	8	8	8	8	8	8	9	11	12	13	14	16	16	16	17	17	16	14	13	12	11	11	11	12	17
18	11	11	10	9	9	9	9	10	11	11	14	17	18	18	20	20	19	14	12	11	9	6	5	5	12	20
19	4	4	4	4	4	4	4	5	6	8	9	12	12	7	7	7	8	8	8	7	6	4	4	4	6	12
20	4	4	3	3	4	4	4	4	7	9	8	8	8	9	8	8	9	9	9	8	7	7	6	6	7	9
21	6	5	4	4	4	4	3	4	7	7	10	(MT)	11	11	9	8	7	7	7	6	5	4	0	(RF)	6	11
22	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	( )
23	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	( )
24	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	( )
25	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	( )
26	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	( )
27	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )	( )
28	3	3	2	2	1	1	3	4	6	9	11	13	(MT)	17	18	17	16	13	12	11	11	10	10	10	9	18
29	10	9	9	9	9	9	10	10	12	14	16	18	19	21	21	22	20	20	19	18	16	16	14	14	15	22
30	14	14	14	13	13	12	11	12	13	14	16	18	21	19	20	21	21	19	18	17	16	16	15	14	16	21
AV	5	5	5	4	4	4	5	6	7	8	9	11	11	11	11	11	11	10	9	8	7	7	6	6	8	
MK	14	14	14	13	13	12	11	12	13	14	16	18	21	21	21	22	21	20	19	18	16	16	15	14		22

SOLAR RADIATION
LANGLEYS

LOGAN WASH
STATION LW02
APR 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	TL	P
1	0	0	0	0	0	0	4	19	43	54	66	74	78	66	58	54	47	31	4	0	0	0	0	0	597	
2	0	0	0	0	0	0	4	27	43	58	70	78	81	78	70	43	19	16	0	0	0	0	0	0	585	
3	0	0	0	0	0	0	0	4	8	12	12	43	58	54	27	23	16	12	0	0	0	0	0	0	267	
4	0	0	0	0	0	0	8	27	43	54	62	58	85	43	47	39	23	12	0	0	0	0	0	0	500	
5	0	0	0	0	0	0	19	43	58	66	74	78	81	78	74	58	47	27	4	0	0	0	0	0	705	
6	0	0	0	0	0	0	12	31	50	62	70	78	81	78	78	66	50	39	12	0	0	0	0	0	705	
7	0	0	0	0	0	0	8	8	16	31	19	16	39	39	27	47	12	23	4	0	0	0	0	0	287	
8	0	0	0	0	0	0	0	12	19	27	47	54	39	47	50	35	27	43	16	4	0	0	0	0	419	
9	0	0	0	0	0	0	0	8	31	50	62	70	78	78	70	70	58	43	23	4	0	0	0	0	643	
10	0	0	0	0	0	0	0	12	35	50	66	74	78	78	78	74	66	16	23	8	0	0	0	0	655	
11	0	0	0	0	0	0	0	12	35	50	62	70	78	(RF)	(RF)	(RF)	(RF)	47	35	8	0	0	0	0	395	
12	0	0	0	0	0	0	0	8	27	43	62	70	74	74	(RF)	43	39	35	12	0	0	0	0	0	484	
13	0	0	0	0	0	0	0	4	27	43	54	70	50	85	81	74	70	54	39	8	0	0	0	0	659	
14	0	0	0	0	0	0	0	16	39	50	66	70	74	(MT)	39	62	23	12	4	0	0	0	0	0	454	
15	0	0	0	0	0	0	0	4	8	12	19	31	16	74	62	62	50	12	0	0	0	0	0	0	349	
16	0	0	0	0	0	0	12	23	47	54	70	74	78	81	74	62	47	31	4	0	0	0	0	0	655	
17	0	0	0	0	0	0	12	27	50	54	74	74	78	62	58	58	39	19	4	0	0	0	0	0	608	
18	0	0	0	0	0	0	12	31	43	58	62	70	58	66	58	50	39	16	4	0	0	0	0	0	566	
19	0	0	0	0	0	0	4	8	19	19	58	78	39	85	78	62	50	39	16	0	0	0	0	0	554	
20	0	0	0	0	0	0	8	31	50	47	39	43	50	39	35	35	43	47	35	0	0	0	0	0	500	
21	0	0	0	0	0	0	12	31	50	66	74	74	78	74	31	23	12	12	0	0	0	0	0	0	535	
22	0	0	0	0	0	8	23	39	47	43	78	78	89	78	31	43	47	31	4	0	0	0	0	0	636	
23	0	0	0	0	0	4	23	43	58	70	74	78	66	(RF)	(RF)	23	43	12	4	0	0	0	0	0	496	
24	0	0	0	0	0	4	19	35	54	66	74	78	81	78	39	(RF)	43	19	0	0	0	0	0	0	589	
25	0	0	0	0	0	4	23	39	54	66	74	81	81	81	74	(RF)	39	31	8	0	0	0	0	0	655	
26	0	0	0	0	0	0	19	(RF)	50	62	74	70	78	70	62	47	31	4	0	0	0	0	0	0	566	
27	0	0	0	0	0	0	16	31	50	62	70	74	74	(RF)	(RF)	35	19	8	0	0	0	0	0	0	438	
28	0	0	0	0	0	0	23	39	54	66	78	78	78	81	78	74	58	47	19	4	0	0	0	0	775	
29	0	0	0	0	0	0	4	23	43	54	66	74	78	78	78	70	47	43	23	4	0	0	0	0	682	
30	0	0	0	0	0	0	4	23	43	54	66	74	78	47	39	74	(RF)	27	16	4	0	0	0	0	546	
TL	0	0	0	0	0	19	268	655	1194	1504	1837	2023	2069	1787	1492	1403	1101	802	310	43	0	0	0	0	****	
PK	0	0	0	0	0	8	23	43	58	70	78	81	89	85	81	74	70	54	39	8	0	0	0	0		

RELATIVE HUMIDITY
PERCENT

LOGAN WASH
STATION LW04
APR 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE	PEAK
1	43	(MF)	(MF)	(MF)	87	89	92	81	55	46	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	92
2	(MF)	80	85	86	88	89	88	91	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	7	11	12	12	16	18	21	44	53	( )	89
3	74	76	78	90	91	93	92	86	75	70	76	93	54	61	84	85	87	60	88	86	86	84	97	97	82	97
4	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
5	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
6	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )	( )
7	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	31	22	17	16	28	30	25	30	48	73	66	50	48	70	( )	73
8	92	96	96	93	95	94	95	96	76	55	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	96
9	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
10	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
11	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
12	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
13	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
14	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	27	24	21	19	21	22	22	22	26	29	37	43	50	56	( )	56
15	64	70	75	75	81	83	88	83	80	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	90	93	96	89	( )	96
16	90	90	92	93	95	97	98	98	95	71	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	98
17	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
18	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
19	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
20	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
21	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
22	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
23	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
24	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
25	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
26	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
27	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
28	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
29	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
30	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	(MF)	( )	( )
V	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	( )	
X	92	96	96	93	95	97	98	98	95	71	76	93	54	61	84	85	87	60	88	86	90	93	97	97		97

J REC: STATUS NR 1 2 481

TEMPERATURE
DEGREE C

LOGAN WASH
STATION LW04
APR 1981
OCCIDENTAL OIL SHALE INC.

HOUR (LOCAL STANDARD TIME)

DAY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	AVE
1	-3	-1	-2	-2	-2	-3	-3	-2	2	4	7	10	13	16	16	17	17	16	15	12	9	7	7	6	6
2	3	1	-1	-1	-1	-2	-2	1	6	9	15	18	18	19	19	18	18	17	16	14	13	14	12	9	10
3	6	7	6	4	4	4	4	4	4	5	4	3	4	6	3	3	3	3	2	2	2	2	1	1	4
4	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )
5	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )
6	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	( )
7	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	(IM)	12	14	15	17	16	14	13	14	12	9	8	8	9	7	12
8	4	3	3	3	3	3	1	2	3	8	8	9	11	12	12	14	14	14	14	13	7	7	6	6	7
9	6	5	5	2	1	1	0	0	4	8	12	16	18	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	12	10	9	8	7
10	7	8	8	4	3	2	1	2	7	12	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
11	9	8	8	7	4	3	2	2	7	12	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	9	( )
12	7	4	4	4	2	2	2	2	7	11	14	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	13	11	10	7
13	9	9	9	8	8	8	8	7	10	13	17	19	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	10
14	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	16	18	19	21	20	20	21	19	18	17	16	14	13	13	17
15	12	10	9	9	9	9	9	8	8	9	12	14	14	15	14	17	17	18	18	16	9	8	7	7	12
16	7	6	4	3	3	2	2	2	3	6	9	12	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	5
17	(RF)	(RF)	7	4	3	3	3	3	6	10	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
18	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	12	12	( )
19	12	10	9	8	8	8	8	8	9	11	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
20	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
21	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	18	17	17	16	14	13	11	9	8	8	( )
22	7	7	6	4	3	7	11	12	13	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
23	3	2	1	-1	-1	4	8	11	14	16	19	20	22	22	23	(RF)	(RF)	(RF)	(RF)	14	12	11	10	7	11
24	0	4	3	2	2	5	11	14	17	20	23	24	25	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	13	11	9	7	12
25	0	5	4	3	3	7	12	15	18	22	24	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
26	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
27	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	( )
28	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	(RF)	19	21	23	24	26	26	27	27	25	23	21	19	16	15	22
29	13	13	11	9	9	6	6	9	13	16	19	22	24	27	28	28	28	28	28	26	20	17	18	17	18
30	16	14	12	11	9	7	7	10	16	19	22	25	27	28	28	28	28	28	27	25	22	21	19	17	19
AV	7	6	5	4	4	4	5	6	9	12	15	16	( )	( )	( )	( )	( )	( )	( )	( )	( )	12	10	9	11
PK	16	14	12	11	9	9	12	15	18	22	24	25	27	28	28	28	28	28	28	26	22	21	19	17	

APPENDIX G

Williams Brothers Pipeline Transportation Report

WILLIAMS BROTHERS ENGINEERING COMPANY
A Resource Sciences Company

RESOURCE SCIENCES CENTER | 6600 S. YALE AVE. | TULSA, OKLAHOMA 74177
PHONE (918) 496-5020 | TELEX 49-7493 WBEC-TUL

February 23, 1981

OCCIDENTAL OIL SHALE, INC.
P. O. Box 2687
Grand Junction, CO 81502

Attention: Frederick H. Kloer

Dear Sir:

This transmits our Report, "Pipeline Transportation of Shale Oil; Phase II, Shale Oil Rheology and Phase III, Pipeline Conceptual Design" dated February, 1981.

This work has been completed in accordance with our assignment from Occidental under Subcontract No. OS-12393 dated July 2, 1980. Phase I Report, "State-of-the-Art Literature Search" dated September 30, 1980 was submitted previously.

Thank you for this opportunity to be of service in advancing your important shale oil development program.

We hope that we can be of futher assistance as your program moves forward.

Very truly yours,

WILLIAMS BROTHERS ENGINEERING COMPANY

RR Burnett

Richard R. Burnett
Project Manager

Attachments: 10 copies

RRB:ek

REPORT

PIPELINE TRANSPORTATION OF SHALE OIL PHASE II: SHALE OIL RHEOLOGY PHASE III: PIPELINE CONCEPTUAL DESIGN

prepared for
OCCIDENTAL OIL SHALE INC.
Grand Junction, Colorado

February 1981

WILLIAMS BROTHERS ENGINEERING COMPANY

A Resource Sciences Company

RESOURCE SCIENCES CENTER • TULSA, OKLAHOMA 74177

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SECTION	EXHIBIT	TITLE
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1. INTRODUCTION

This report deals with the rheology and pipeline transportation of shale oil.

The assignment to Williams Brothers includes three Phases, as follows:

Phase I	-	State-of-the-Art Literature Search
Phase II	-	Investigation of Shale Oil Rheology
Phase III	-	Conceptual Pipeline Design

Phase I, State-of-the-Art Literature Search has been submitted in Williams Brothers' report to Occidental, September 30, 1980. This includes a bibliography of published technical information on shale oils and an abstract of the state-of-the-art with particular attention to shale oil properties which affect pipeline transportation.

Phases II and III are combined in this present report.

Rheology investigations under Phase II includes pour points, and the effects of temperature on viscosity, enthalpy and density - those properties of primary concern in pipeline design. The investigations include the properties of raw modified in-situ (MIS) shale oil without treatment or additive plus a preliminary investigation of the possible effect of an additive in lowering pour points and viscosities. Section 7 of this report present the results and the conclusions are given in Section 2.

The conceptual pipeline under Phase III is designed to transport 100,000 barrels per day of raw MIS shale oil from a producing area in western Colorado to a destination east of the Rocky Mountains over a distance of 260 miles. The high viscosities and pour points of this shale oil require that a distribution of heat be maintained over the length of the pipeline. The method recommended for handling this problem is presented in this report and the conclusions and recommendations are summarized in Section 2.

2. PRELIMINARY CONCLUSIONS AND RECOMMENDATIONS

- The laboratory tests on viscosity, pour point, density and enthalpy are based on samples of a prototype production of an MIS shale oil. Ultimately, full-scale production is expected to produce shale oils containing a range of properties from each retort, varying somewhat with the age of the retort. The production of several retorts, at different stages, when blended, will contain a range of properties which should be investigated farther when available.

- Transportation costs of the raw MIS shale oil by pipeline are in the range of 12 cents per 100 barrel-miles, or about 0.7 cents per ton-mile (1980 dollars). This cost includes debt retirement with interest and direct operating expenses. Other costs of the enterprise, such as depreciation, taxes and return on investment, are not included. This cost competes favorably with rail or tank truck transportation costs. A pipeline also can usually take a more direct, shortened route over mountainous terrain, and minimize the effects on the environment - further advantages.

- The main design and operating challenge in pipelining raw MIS shale oil is to use heat available from the producing process, supplemented as necessary, to control viscosities and maintain temperatures above the pour point. The economic solution favors a heavily insulated pipeline buried below frost levels. Intermediate heaters along the pipeline and emergency pumps to maintain a minimum flow rate in either direction are necessary to insure continuous heat distribution over the length of the pipeline in case of power failure. The thick insulation also lengthens the cool-down time available

for repairs during a complete stoppage of flow.

- Design and operation of the shale oil pipeline at design flow rates are typical of liquid petroleum pipelines. During this operation the use of intermediate heaters is not required.

- For a design flow rate of 100,000 barrels per day, the recommended pipeline system has 20" mainline pipe with 6" thick polyurethane insulation and a polyethylene jacket.

- With a 260-mile long pipeline assumed in this study, the pipeline includes:

    - Two pump stations with electric-driven centrifugal pumps.

    - Six heating stations for flow rates as low as 7,500 BPD.

    - One pressure reducing station used only at reduced flow rates.

    - Two emergency diesel engine driven pumping units with screw-type pumps to sustain a minimum flow rate of 7,500 BPD in either direction.

    - Provision for reversal of flow direction to assure continuity of flow and heat distribution in case of terminal storage problems.

    - Communications and supervisory control systems for remote control monitoring of operations and for system maintenance.

- Central operating, maintenance and administrative facilities.

- The use of an additive pour point depressant should be further examined. Comparative tests of an additive showed that improvements are possible but that the durability of the improvements remains in question. Pour points were initially reduced in the laboratory but subsequent tests gave mixed results on pour point improvement. No definite conclusions can be given on this basis, but the need for further testing is apparent since the pipeline capital investment and operating costs would benefit considerably if a reliable and economical additive can be found.

3. PIPELINE ROUTE AND CONSTRUCTION

A. Pipeline Route

A typical pipeline route from the producing area to an arbitrary destination across the Rocky Mountains was selected to generate pipeline length, elevation profile, typical environmental conditions and a basis for estimating costs of construction, operation and maintenance. The route generally follows valleys where roads exist, but the route and right-of-way is separated from existing roads so that an access trail along the pipeline is cleared for construction and maintenance.

B. Line Pipe

The pipeline is conventional API Grade 5LX-60 line pipe, 20" O.D. 0.344" wt with 6" thick polyurethane which is foamed into a polyethylene jacket. This insulation process has broad application for cross-country pipelines and the procedure for insulation of field joints is well established. Maximum steady state operating pressure for the pipe is 1485 psig.

C. Typical Pipeline Construction

Conventional buried pipeline construction methods are used with burial depths that allow about one foot clearance between the top of the polythylene jacket and the estimated frost line depth. This extra depth isolates the pipeline from high local bending stresses associated with "frost heave" and adds an extra margin of earth insulation to conserve heat. Exhibit 3-1 shows a typical

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cross section of the buried pipeline.

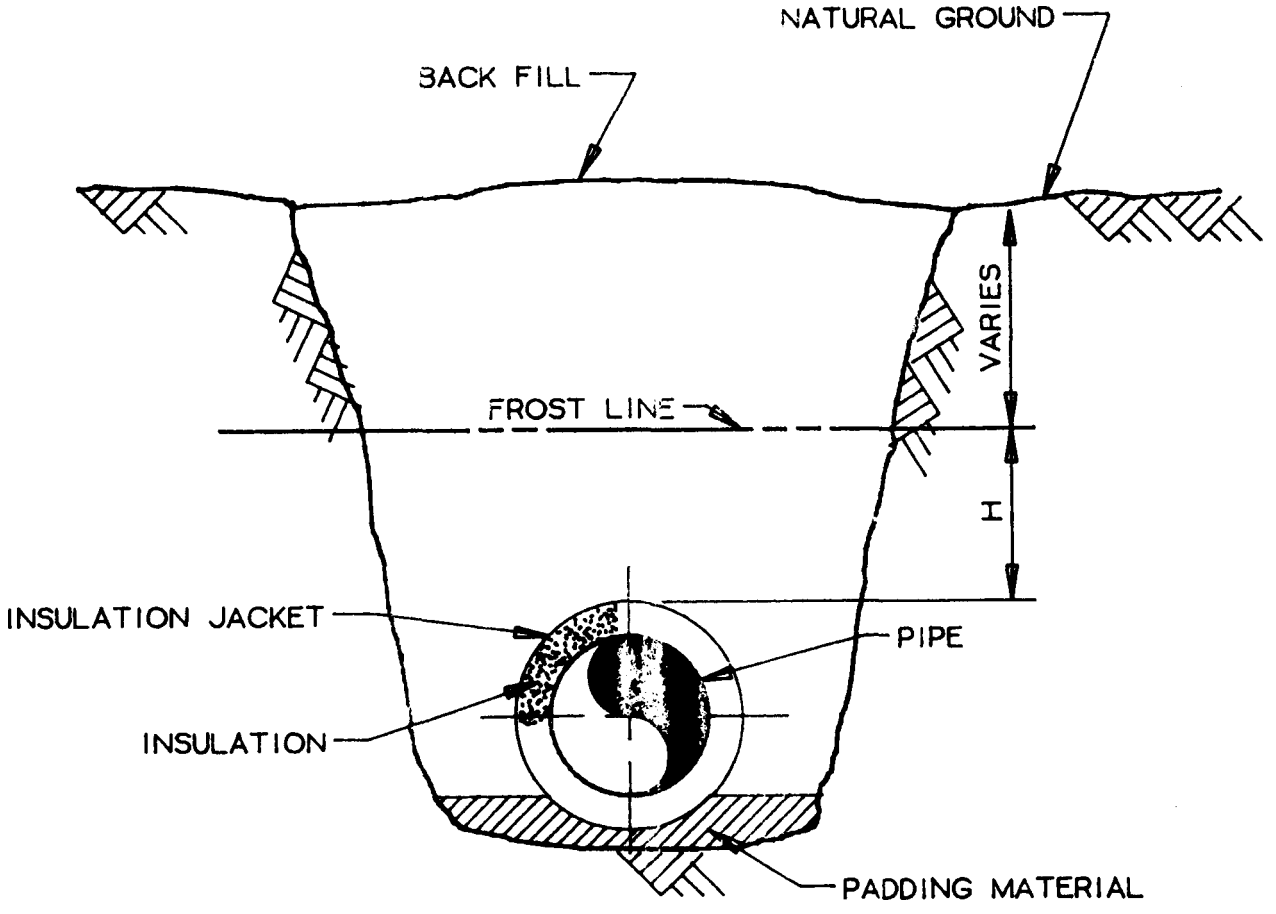
To control stresses in the pipe and insulation, the design concept is based on longitudinal and transverse restraint. This invlolves consideration of strategically placed anchorage at certain locations of change in vertical or horizontal alignment.

D. Major Crossings

Design and construction of any major crossing will be guided by the specific requirements for the crossing and generally by API Recommended Practice for Liquid Petroleum Pipelines Crossing Railroads and Highways, API RP 1102, as well ANSI/ASME Standard B31.4 and applicable regulations.

E. Main Line Valves

Main line block and check valves are installed in accord with recommended standards, including ANSI/ASME B31.4, and applicable regulations. Maximum distance between block valves is 10 miles. Block and check valves are suitably located at pump stations and major water crossings.



WILLIAMS BROTHERS ENGINEERING COMPANY

A Resource Sciences company

420 TULSA, OKLAHOMA

TYPICAL BURIED INSTALLATION
INSULATED PIPELINE
OCCIDENTAL SHALE OIL, INC.

Date SEPT., 1980

Approved

EXHIBIT 3-1

DES-F-A1000

4. PUMP STATIONS AND HEATING STATIONS

In addition to the electric-driven main pumping units, the first pump station includes a diesel engin driven screw-type pump for emergency use during start-up. This pump may also be required to maintain flow during any intervals of power outage that include any critical pump station. Exhibit 4-1 illustrates a typical pump station flow diagram.

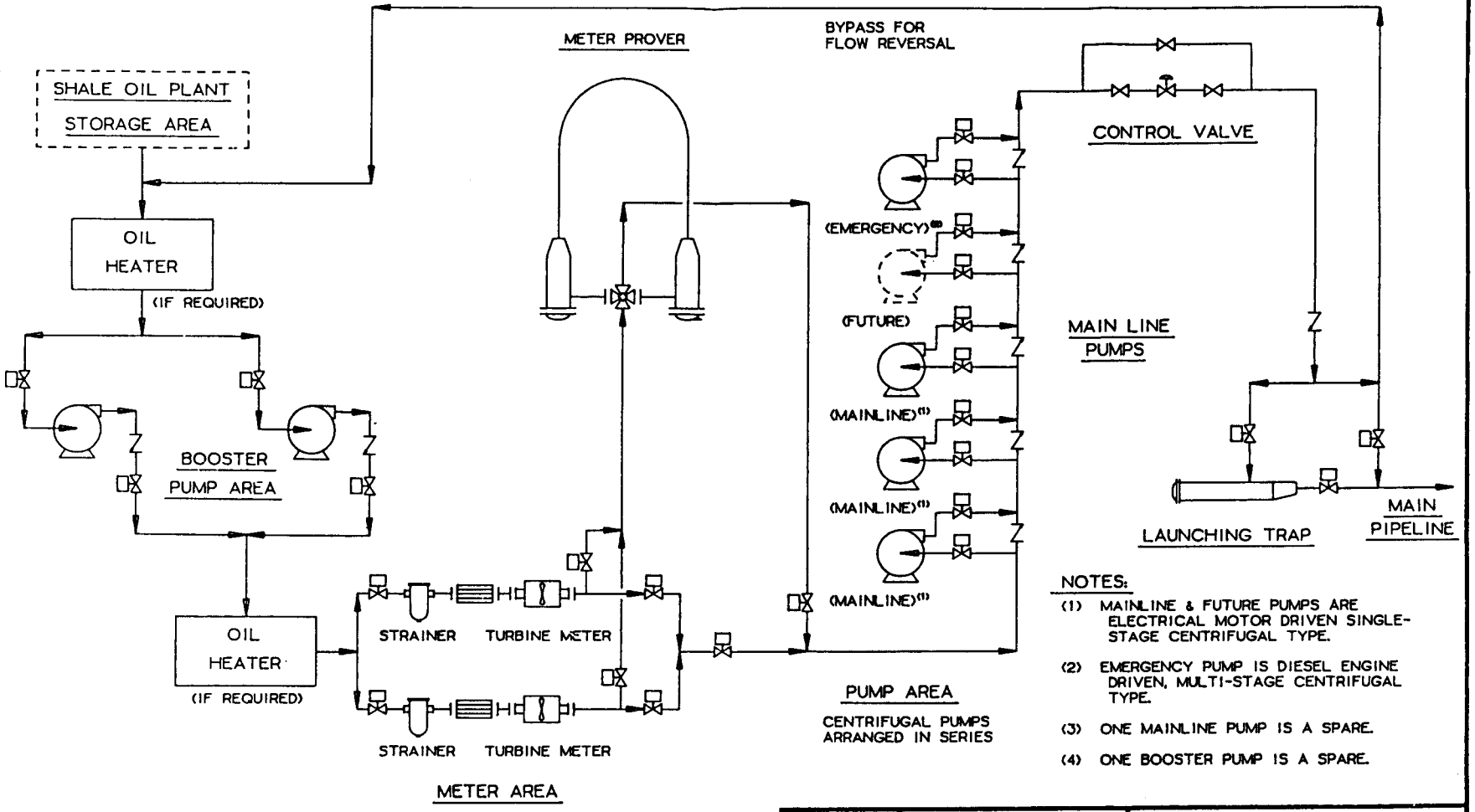
Each pump station is remotely controlled through the communications and supervisory control systems during normal starting, stopping and running operations. Exhibit 4-2 shows an arrangement of the main facilities.

The shale oil pumping system is controlled by remote setting of pump station outbound pressure. Local pre-set controls are provided to over-ride remote settings under certain unscheduled events to protect the pump stations and pipeline. The pump station control system includes pump suction pressure, pump discharge pressure and flow rate. The flow rate at intermediate pump stations is measured for operational purposes only and is provided by an orifice meter or similar device. Pump station outbound pressure is controlled through a control valve in the discharge station pipeline.

The main line pumps are single-stage centrigugal. Arrangement of the pumps in series is favored because of the pipeline elevation profile and the design flow rate.

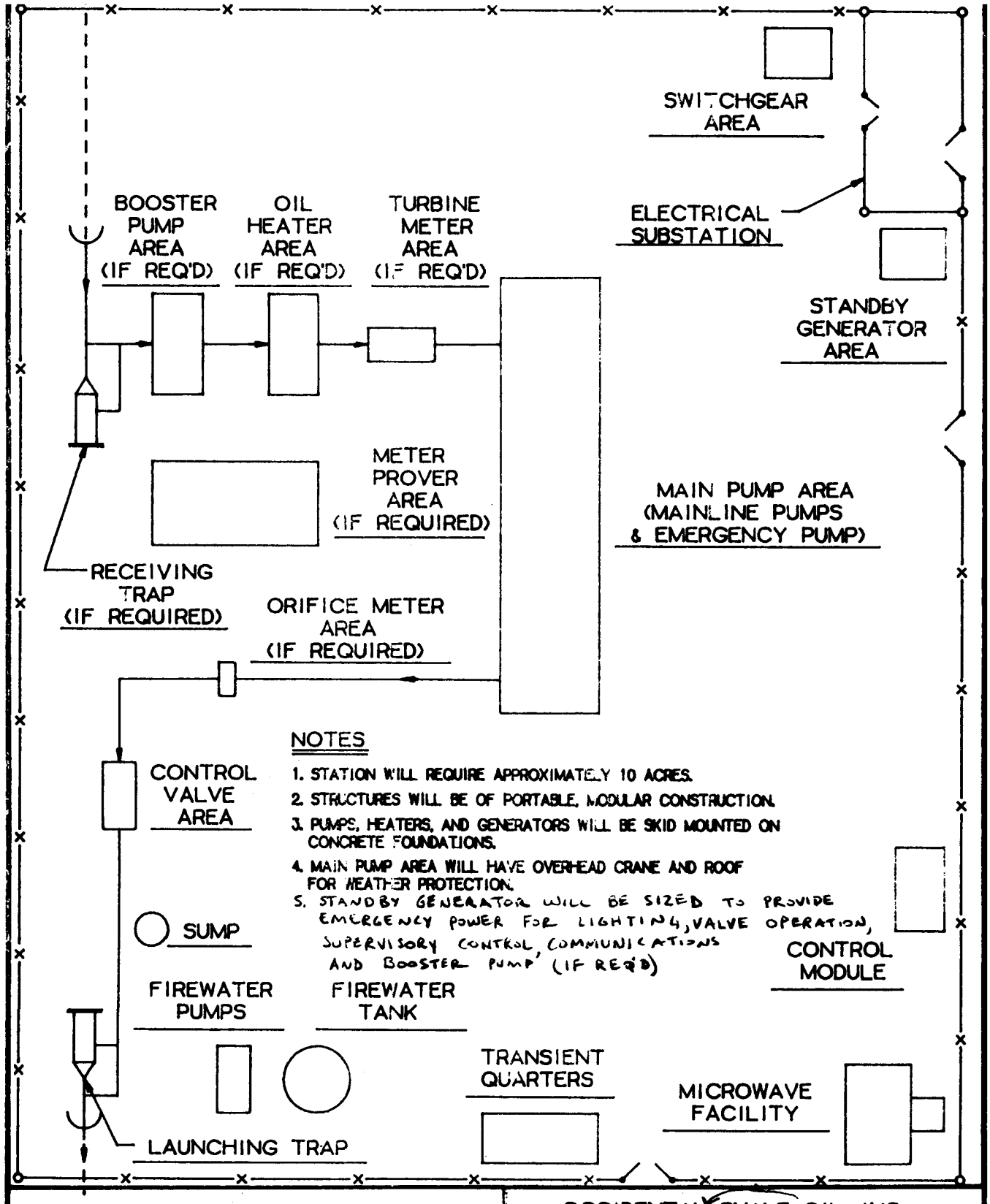
Each pump station is provided with switchgear, control and communications cubicles and a microwave radio communications tower. Quarters for visiting maintenance personnel are also provided.

The electric power supply is presumed to be available within a reasonable distance. Each pump station plot includes space for a sub-station with power metering equipment. The power supplies the main line pump drivers, valve operators, floating battery for communications, control and monitoring devices and general utility requirements.



WILLIAMS BROTHERS ENGINEERING COMPANY A Resource Sciences company TULSA, OKLAHOMA	FLOW DIAGRAM PUMP STATION NO. 1 OCCIDENTAL OIL SHALE, INC
	Date SEPT., 1980 Approved
	EXHIBIT 4-1

DATE PLOTTED 09-03-81



NOTES

1. STATION WILL REQUIRE APPROXIMATELY 10 ACRES.
2. STRUCTURES WILL BE OF PORTABLE, MODULAR CONSTRUCTION.
3. PUMPS, HEATERS, AND GENERATORS WILL BE SKID MOUNTED ON CONCRETE FOUNDATIONS.
4. MAIN PUMP AREA WILL HAVE OVERHEAD CRANE AND ROOF FOR WEATHER PROTECTION.
5. STANDBY GENERATOR WILL BE SIZED TO PROVIDE EMERGENCY POWER FOR LIGHTING, VALVE OPERATION, SUPERVISORY CONTROL, COMMUNICATIONS AND BOOSTER PUMP (IF REQ'D)

WILLIAMS BROTHERS ENGINEERING COMPANY

A Resource Sciences company

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TULSA, OKLAHOMA

OCCIDENTAL SHALE OIL, INC.
PUMP STATION
GENERAL LAYOUT

Dwn L.E.C.	Date 9-19-80	Ckd	App
Job 4338	Dwg No EXHIBIT 4-2		Rev 0

TABLE 4-3

SUMMARY OF PUMP AND HEATING STATIONS

Flow Rate (MBD)	7.5	15	30	50	75	100	150	200
Pump Station								
No. 1 No. of Pumps	1	1	1	2	3	3	4	5
Install. BHP per pump	1650	1650	1650	1650	1650	1650	1650	1650
No. 2 No. of Pumps	--	--	--	--	--	--	--	4
BHP per Pump	--	--	--	--	--	--	--	1650
No. 3 No. of Pumps	--	--	--	--	--	--	4	4
BHP per Pump	--	--	--	--	--	--	1650	1650
No. 4 No. of Pumps	--	--	--	--	--	2	4	4
BHP per Pump	--	--	--	--	--	1650	1650	1650
No. 5 No. of Pumps	--	--	--	--	--	--	--	4
BHP per Pump	--	--	--	--	--	--	--	1650
Total BHP	1650	1650	1650	3300	4950	8250	19,800	34,650
Heating Stations								
No. 1	8	--	--	--	--	--	--	--
2	8	8	--	--	--	--	--	--
3	8	--	--	--	--	--	--	--
4	8	8	16	--	--	--	--	--
5	8	--	--	--	--	--	--	--
6	8	8	--	--	--	--	--	--
Total BTU/Hr.	48	24	16	--	-	--	--	--

NOTE: One spare pump at each station, except where only one pump shown at P.S. #1 emergency pump acts as its spare.

EXHIBIT 4-2

5. GENERAL FACILITIES

A. Maintenance Bases and Offices

Major maintenance bases are provided at the supply and delivery terminals of the pipeline. Major repair materials and specialized work equipment are located at these two bases. Maintenance specialists and light vehicles for mechanical, electrical, control and communications repairs are based at these locations.

An intermediate maintenance base is also located strategically to provide emergency investigation and routine patrol of pipeline and pump stations. Aerial pipeline surveillance is presumed to be available on a contract basis.

The pipeline control center and administrative offices are in one location -- either the supply or the delivery terminal. These include office spaces for the system manager, accounting and maintenance personnel and records.

B. Communications and Supervisory Control Systems

The communications system is based on a microwave radio backbone system installed and operated by the pipeline owner. The importance of this system indicates remote repeaters designed for unattended continuity over at least six month time periods. The capacity of the system includes requirements for remote control and monitoring signals, mobile voice channels, point-to-point voice and teleprinter circuits.

The supervisory control system includes the remote control of pump stations, continuous monitoring of system data with periodic printout and remote control of selected main line block valves. Remote terminal units are located at each pump station and the master terminal unit is located at the pipeline control center along with the desired visual displays.

6. FLOW STOPPAGE AND RESTARTING

Circumstances under which the pipeline flow may stop include:

1. Low shale oil inventory at the supply terminal
2. High shale oil inventory at the delivery terminal
3. Power failure causing shut down of any pump station required to maintain flow
4. Pump station mechanical, electrical or control failure causing complete shut down of a critical station
5. Pipeline leak or rupture

If the flow is stopped during the winter months, a period of a few days is required to cool the shale oil down to 60° F, assuming the frost line is at least 12 inches above the top of the polyethylene jacket. This cool down time is lengthened by thicker insulation and by higher local oil temperatures at the time of flow stoppage. In the range of 60 to 150° F initial oil temperatures, the calculated cooling time to reach an oil temperature of 60° F through 6 inches insulation thickness over 20" O.D. pipe is tabulated here:

Initial Oil Temperature °F	Time for Cooling to 60° F HOURS
65	56
70	106
80	189
90	256
100	318
150	540

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The likelihood of power failure appears to be greater during severe winter weather. Icing can occur on high voltage tranmission lines while falling branches on lower voltage distribution lines occasionally can cause interruption on high voltage lines.

The likelihood of shutting down the pipeline flow due to inventory problems at either terminal is eliminated by providing terminal storage facilities whose levels can be partially controlled by the pipeline operator and by providing the capability reversing the pipeline flow direction. A local failure at a critical pump station would be manageable within the cool down time. A mechanical failure affecting only one pumping unit would leave the other units available to maintain pipeline flow. A local electrical or control failure is assumed to be correctable less than the cool down time. A major fire at a pump station would require the use of emergency pumping equipment during repairs.

Emergency 200 HP diesel engine driven pumping units are intalled to sustain a flow rate of 7,500 BPD in conjunction with heating stations to prevent cool down below 60° F. One emergency pumping unit is located at the first pump station and another unit at the delivery terminal for reversing the direction of the flow. Provision is also made for bypassing main line check valves and pump stations in case flow needs to be reversed.

7. SHALE OIL PROPERTIES

The design basis for this investigation requires that the shale oil properties be consistent and predictable over the range of temperatures expected in the operating pipeline. A second requirement is that these properties fall within the range of practical and economic pipeline operation.

The properties of concern during normal operation are viscosity, enthalpy and density. A second concern is the effect of shut downs with prolonged flow stoppage. The alternative is to maintain flow and temperature distribution in the pipeline at all times.

The design configuration is based on deep burial of the pipeline below the frost line to keep the pipeline essentially restrained against axial or transverse movement. At this depth, ambient soil temperatures would approach 32° F. Insulation is provided to improve the oil temperature distribution and the retention of heat along the pipeline. While insulation thickness is based on minimizing total transport costs during normal operation, a second benefit is to slow the rate of cooling during a shut down and allow time for taking emergency action to maintain heat and flow in the system.

The rheology of shale oils has been investigated from the standpoint of determining that the requirements described above can be met. Special attention has been directed to the viscosity and heat content, or enthalpy characteristics over the potential range of operating temperatures.

Viscosity tests were run in six test series. Four series of tests utilized only shale oil untreated from Retort No. 6. Two of these were tested on the rotating viscometer. The third and fourth were comparative tests on the viscometer versus the bench model pipeline. The remaining two test series were on samples treated with a pour point depressant. These involved several comparative tests for control.

Exhibit 7-1 shows the results of these tests graphically as viscosity versus temperature and are described here:

Series No. 1, August 1980. Samples from the one-gallon containers with essentially no heating or agitation except that received furing shipment, handling and testing. Pour points of samples from different containers ranged from 44 to 55° F.

Series No. 2, August 1980. Sampled from the one-gallon can, heated in an oven for three to four hours at 150 to 167° F, then stirred for three hours with an agitator. Pour points ranged from 42 to 58° F.

Series Nos. 3 and 4, September 1980. Bench model pipeline versus viscometer tests. Note that viscosities derived from the model pipeline are considerably lower than those of the rotating viscometer.

Series No. 5, November 1980. Sampled from a drum of shale oil sampled from Retort No. 6. Part of samples treated with .05 gm Nalco 5351 to 100 ml shale oil. Certain tests showed 33 to 34° F reduction

in pour point after Nalco 5351 treatment compared to concurrent samples untreated. However, pour points fluctuated widely after periods of ageing, one indicating an increase in pour point when Nalco was added.

A second sample was split four ways:

A. Untreated (P. P. = 67° F)

B. .05 gm Nalco 5351/100 ml oil (P. P. = 33° F)

C. .05 gm Nalco in 2cc toluene/100 ml oil (P. P. = 34° F)

D. 2cc toluene only/100 ml oil (P. P. = 64° F)

Viscosities tested in the rotating viscometer and plotted on Exhibit 7-1.

Series No. 6, December 1980. Sampled from the drum and treated with Nalco 5351 - .05 gm/100 ml oil. (P. P. = 25° F) viscosities test at 90° to 150° F and shown on Exhibit 7-1. After resting overnight, sample became solid at room temperature.

Enthalpy tests and densities were run only on the original samples with no treatment. The results are shown on Exhibit 7-2.

The rheology and related tests offer the conclustion that shale oil properties for temperatures above 60 to 65° F are predictable within the range of samples tested. For this preliminary evaluation the data obtained from the first test series have been used.

The variability of these properties over the life of a single retort or of composite blends of a group of retorts remains unknown at this time.

The results of the very limited tests of oils treated with pour point depressant indicate that some economic possibilities may exist. This should be explored further.

Examination of the rotating viscometer test data shows a tendency for shale oil to become non-Newtonion at temperatures near the pour point. This also requires further testing to determine whether or not a serious starting problem could develop when a pipeline shut down is prolonged and the oil is permitted to cool to the pour point region of temperature. Since the alternative of using additive treatment to lower pour points has not so far been demonstrated, the preliminary pipeline design includes emergency pumping and heating equipment to prevent such a cool down.

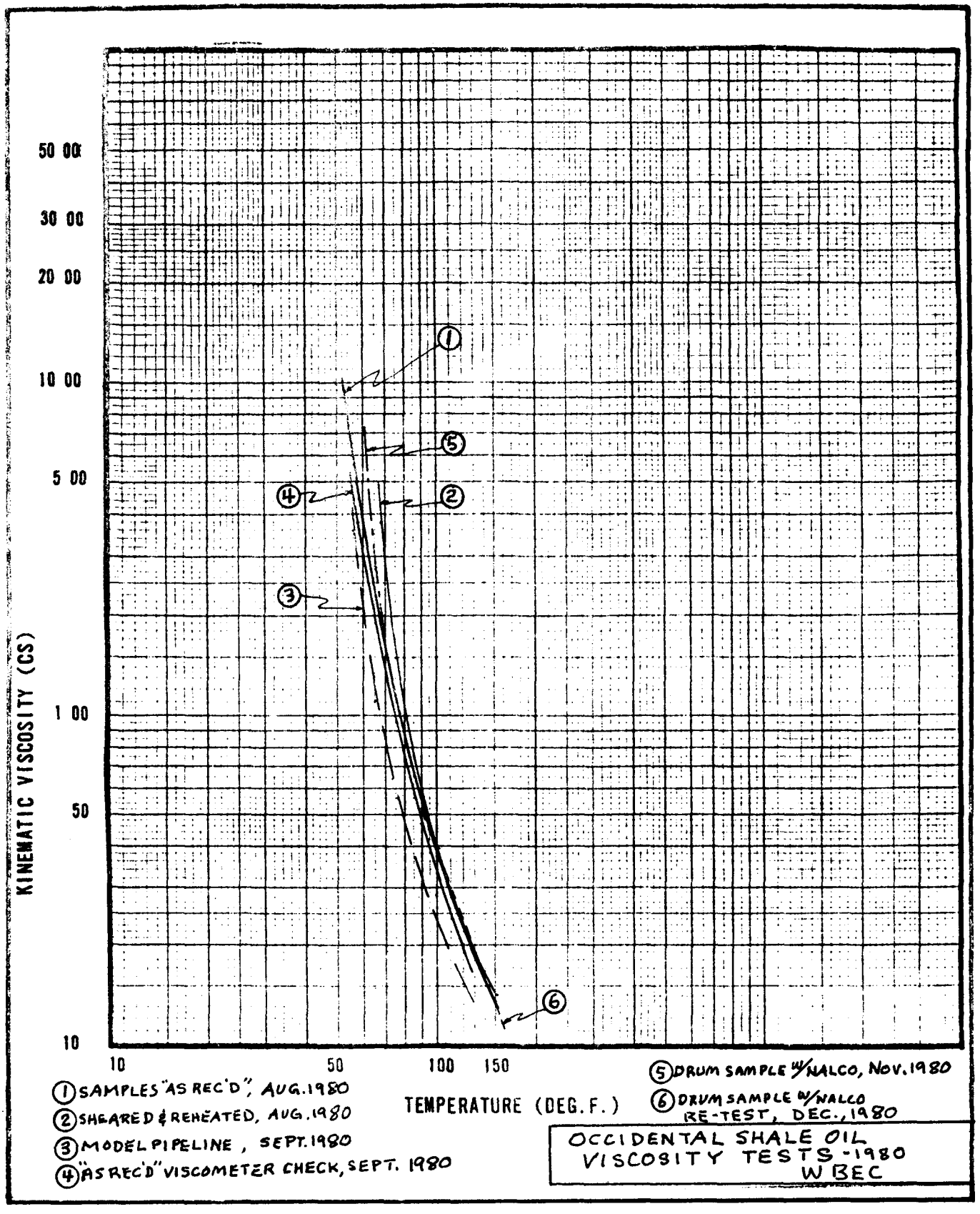
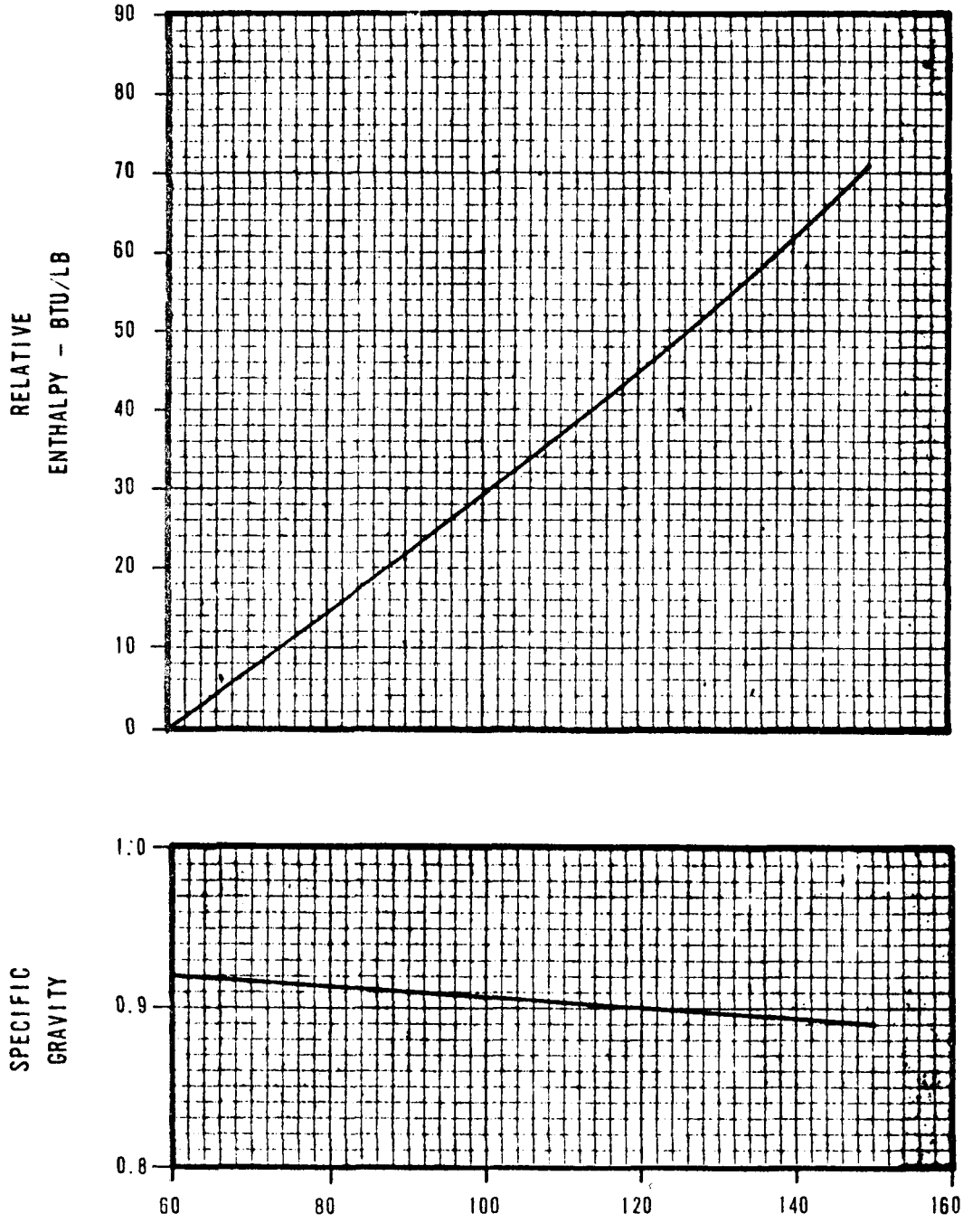

50 00
30 00
20 00
10 00
5 00
1 00
50
10
KINEMATIC VISCOSITY (CS)
10
50
100
150
TEMPERATURE (DEG. F.)
① SAMPLES "AS REC'D", AUG. 1980
② SHEARED & REHEATED, AUG. 1980
③ MODEL PIPELINE, SEPT. 1980
④ "AS REC'D" VISCOMETER CHECK, SEPT. 1980
⑤ DRUM SAMPLE W/NALCO, NOV. 1980
⑥ DRUM SAMPLE W/NALCO RE-TEST, DEC., 1980
OCCIDENTAL SHALE OIL
VISCOSITY TESTS - 1980
WBEC

EXHIBIT 7-1



ENTHALPY ADAPTED FROM SAMPLE TESTS OF SEPT, 1980 BY P-V-T; S.G. BASED ON WBEC DATA, SEPT. 1980

WILLIAMS BROTHERS ENGINEERING COMPANY *A Resource Sciences company* TULSA, OKLAHOMA	RELATIVE ENTHALPY & SPECIFIC GRAVITY VS TEMPERATURE RETORT NO 6 SHALE OIL OCCIDENTAL OIL SHALE, INC.
	Date SEPT., 1980 Approved RRB
	EXHIBIT 7-2

DES-F-A1000

OCCIDENTAL SHALE OIL
Bench Model Pipeline Tests
Drum Sample, Retort No. 6

Loop Equiv. Length: 108.5 LFT.; I.D. = 0.305"

Date	Run No.	Mean. Temp.	SP. GR.	ΔH FT	Flow Rate BPH	Calc. Vis.C.S.	R	$SR_{sec^{-1}}$
9.9.80	1	64.98	.9121	182.26	.29948	110.18	19.73	289.4
	2	64.49	.9122	127.82	.20904	110.70	13.71	202.0
	3	63.25	.9123	83.52	.13028	116.06	8.15	125.9
	4	62.75	.9126	18.98	.02849	120.57	1.716	27.5
9.10.80	1	55.25	.9159	126.05	.06109	373.56	1.19	59.0
	2	57.71	.9150	199.35	.12522	288.22	3.15	121.0
	3	60.95	.9137	255.23	.23291	198.40	8.52	225.1
	4	58.75	.9146	20.20	.01250	292.61	0.31	12.1
	5	56.50	.9155	55.49	.03626	277.00	0.95	35.0
9.10.80	1	78.25	.9068	171.36	.54660	56.76	69.91	528.2
	2	77.00	.9073	118.59	.38916	55.17	51.20	376.1
	3	75.25	.9080	82.64	.26719	56.00	34.64	258.2
	4	74.25	.9084	45.75	.14868	55.71	19.37	143.7
	5	74.50	.9082	10.17	.04934	37.32	9.60	47.7
9.10.80	1	100.50	.8980	211.48	1.32978	28.79	335.3	1285
	2	100.25	.8981	158.11	1.00566	28.46	256.5	972
	3	100.25	.8981	96.41	.62816	27.79	164.1	607
	4	99.50	.8983	32.13	.31827	18.28	126.4	308
	5	99.25	.8984	13.49	.12617	19.36	47.3	121.9
9.11.80	1	120.25	.8900	108.18	1.16621	16.79	504.1	1127
	2	120.00	.8901	66.67	.76006	15.88	347.4	734
	3	120.37	.8899	40.99	.50222	14.78	246.7	485.3
	4	120.62	.8898	10.64	.17685	10.89	117.9	170.9

EXHIBIT 7-3

8. THERMAL HYDRAULIC ANALYSIS

A. Method of Hydraulic Analysis

The pipeline is divided into segments whose length is adjusted to obtain the required accuracy in results. An energy balance is performed on each segment by equating the change in thermal and hydraulic energy of the fluid over the segment length to the thermal energy loss to the surroundings along the segment. Changes in thermal energy storage rate are also taken into account in cases where this is significant.

The input to the first segment consists of fluid pressure, flow rate and temperature. The calculated output of this segment becomes the input of the next segment, this procedure being continued over the entire pipeline length.

The energy balance for each segment states that:

> Fluid rate of energy input minus fluid rate of energy output is equal to
>
> > rate of energy loss to surroundings plus rate of energy storage.

Algebraically, this can be written:

$$Q_1 r_1 (H_1 + h_1/J) - Q_2 r_2 (H_2 + h_2/J) = q_s + VL\bar{r}\bar{c}\, dt/d\theta \quad \text{(BTU/Hr)} \qquad (1)$$

Where:

Subscripts "1" and "2" denote upstream and downstream ends of the segment, respectively. The bar above the symbol indicates mean value obtained from log mean temperature of the segment.

Q = Volumetric flow rate, BPH
r = Specific weight, Lb/Bbl
H = Heat content at temperature, BTU/LB
h = Liquid head, feet
J = Mechanical equivalent of heat, FT-LB/BTU
q_s = Heat loss rate to surroundings for total segment, BTU/HR
V = Volume per unit length, BBL/MILE
L = Segment length, miles
$\bar{c}$ = Mean specific heat over the segment length, BTU/LB - ^{o}F
$dt/d\theta$ = Rate of mean temperature change, ^{o}F/Hour

The second relationship is the continuity law which states:

Mass Input Rate minus Mass Output Rate is equal to Mass Storage Rate.

Algebraically, this is:

$$Q_1 r_1 - Q_2 r_2 = VLB\bar{r}\, dt/d\theta \quad \text{(LB/HR)} \tag{2}$$

Where B = Thermal coefficient of cubical expansion, per ^{o}F. The relation between h_1 and h_2 is obtained from the Darcy formula:

$$h_1 - h_2 = \frac{322.1\bar{Q}^{2}L}{F^{2}\ d^{5}} \tag{3}$$

Where $\bar{Q}$ = mean volumetric flow rate, BPH

F = Transmission Coefficient, dimensionless
d = Pipe internal diameter, inches

The mean volmetric flow rate is calculated from:

$$\bar{Q} = \frac{1}{\bar{r}}\left[Q_1 r_1 + \frac{(r_1+\bar{r})}{2}\ V\ \frac{L}{2}\ B\ dt/d\theta\right] \tag{4}$$

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The transmission coefficient is obtained from the Modified Colebrook-White function:

$$F = -4 \log (e/3.7d + 1.4125\ F/R) \quad (5)$$

Where e = internal pipe roughness, inches
R = Reynolds Number

and

$$R = 2213.8\ \bar{Q}/\ d\bar{u} \quad (6)$$

in which

$\bar{u}$ = mean liquid kinematic viscosity centistokes

The rate of heat loss to the surroundings, q_s is represented by a relation of the form:

$$q_s = A\ LU\ \overline{\Delta t} \quad (7)$$

Where A = Surface area per unit length, FT 2 mile
U = Overall heat transfer coefficient BTU/Hr-FT^2-^oF

The heat transfer coefficient is built up by combining the liquid film coefficient with heat transfer through insulation and soil or surrounding air. In the case of an above ground pipeline the external film coefficient caused by air movement around the surface and radiation from the surface are partially offset by solar heat received during the daylight hours. This solar effect can cause the heat storage rate and mass storage rate to differ significantly from zero. Unsteady flow results in that case.

Calculations are also required for each segment for obtaining log mean liquid temperature, viscosity, specific heat and specific weight.

Log mean temperature over the segment length is:

$$\bar{t} = t_a + \overline{\Delta t} = t_a + (\Delta t_1 - \Delta t_2)\ /\ln (\Delta t_1/\Delta t_2) \quad (8)$$

Where t_a = ambient temperature, ^{o}F

$\overline{\Delta t}$ = log mean temperature difference, ^{o}F

Δt_1 and Δt_2 = difference between oil and ambient temperatures at the segment ends, ^{o}F
e.g. $\Delta t_1 = t_1 - t_a$

Specific heat can be described by a second order function of the temperature:

$$H = a + bt + ct^2 \quad (9)$$

Specific weight usually can be described by a first order function with sufficient accuracy:

$$r = d + et \quad (10)$$

Viscosity can be described in the following form:

$$\ln u = a + bt + c\left[\ln(t)\right] \times d\left[\ln(t)\right]^2 \quad (11)$$

B. Results of Thermal Hydraulic Analyses

The analyses provide data for illustrating the hydraulic gradients, temperature distribution curves and pump station and heating station locations. The basic design case for a 100,000 BPD flow rate is shown in Figure 8-6. This is a 20" O.D. pipeline with 6" insulation thickness. The upstream shale oil temperature is assumed to be 100 ^{o}F with no heating required. Assuming the flow rate to be continuous at 100,000 BPD, no heating is required along the pipeline. Two pump stations are required. These mainly serve to lift the flowing stream over peaks in the elevation profile. Downstream of the highest elevation point, flow follows the elevation changes generally downhill without the need for additional pump stations.

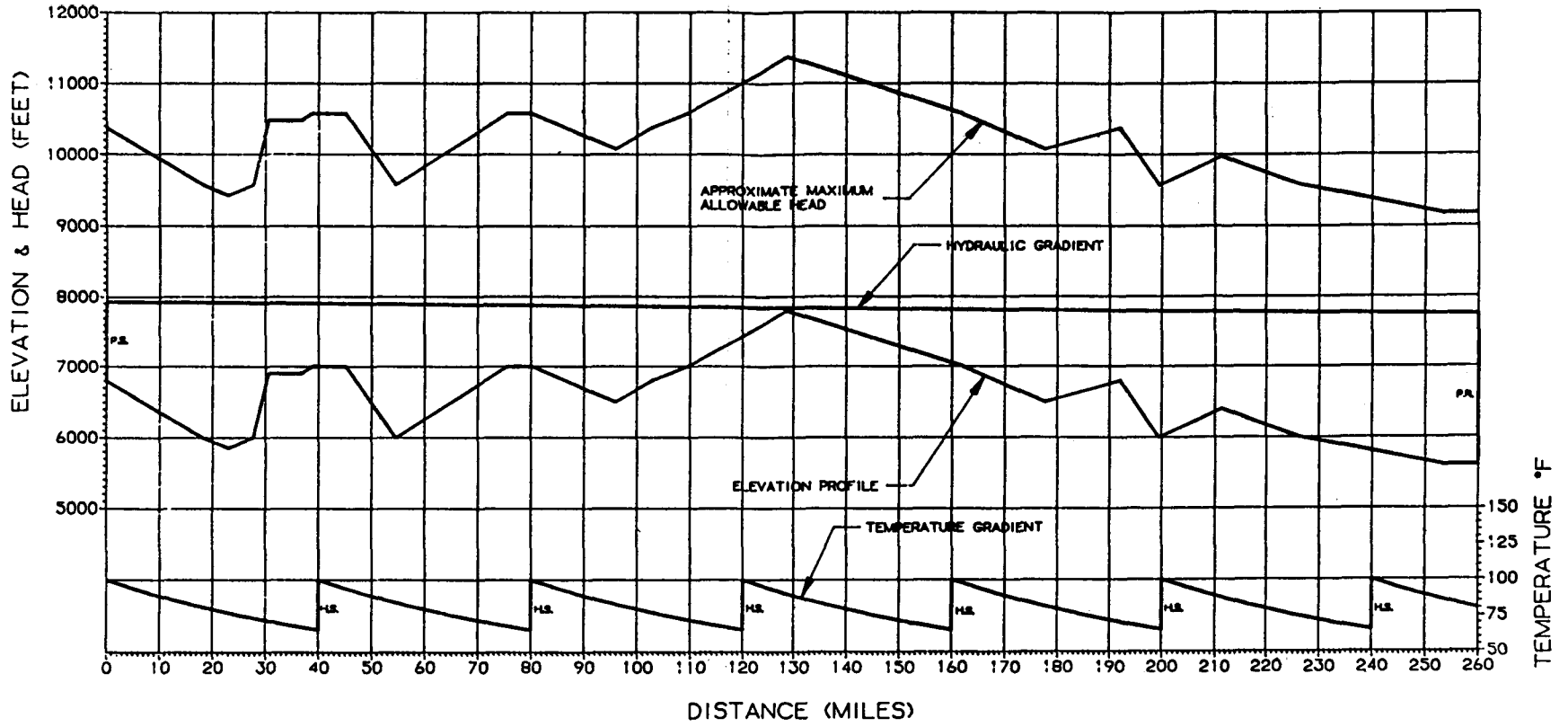
Figures 8-1, 8-2, 8-3, 8-4, 8-5, 8-7 and 8-8 show the same pipeline design operating at flow rates of 7,500, 15,000, 30,000, 50,000, 75,000, 150,000 and 200,000 BPD respectively. Because of more rapid heat loss along the pipeline at lower flow rates, the maximum number of intermediate heating stations is required for the 7,500 BPD flow rate. At this minimum flow rate, heating stations are needed at about 40 mile spacing to maintain temperatures above 60 ^{o}F. Also at these lower flow rates, a pressure reducing station is required at the delivery terminal to prevent formation of vapor and two-phase flow in the downhill portions of the pipeline. At flow rates above 100,000 BPD, no heating or pressure reducing stations are used.

C. Transient Pressures

An analysis of transient pressures along the pipeline should be made when the final pipeline route, elevation profile and pump station locations have been selected. The mountanious terrain suggests the possibility of over-pressuring certain areas under transient conditions when an electric power failure occurs. Also, the possibility of liquid column separation with vaporization followed by rapid collaps of vapor pockets should be examined. Review of the hypothetical profile and hydraulic gradients shown in Exhibit 8-1 through 8-8 reveals possibilities of both types. In Exhibit 8-8, possible high surge pressures in the regions of mile 0 to 28, 48 to 60, 80 to 105, 145 to 260 would require study for protection from high pressures. Most of these problems can be solved by installing a properly designed local automatic

control system for each pump station. The possibility of low pressure column separation is apparent in the region of mile 192 on Exhibit 8-8 and in other regions on other exhibits.

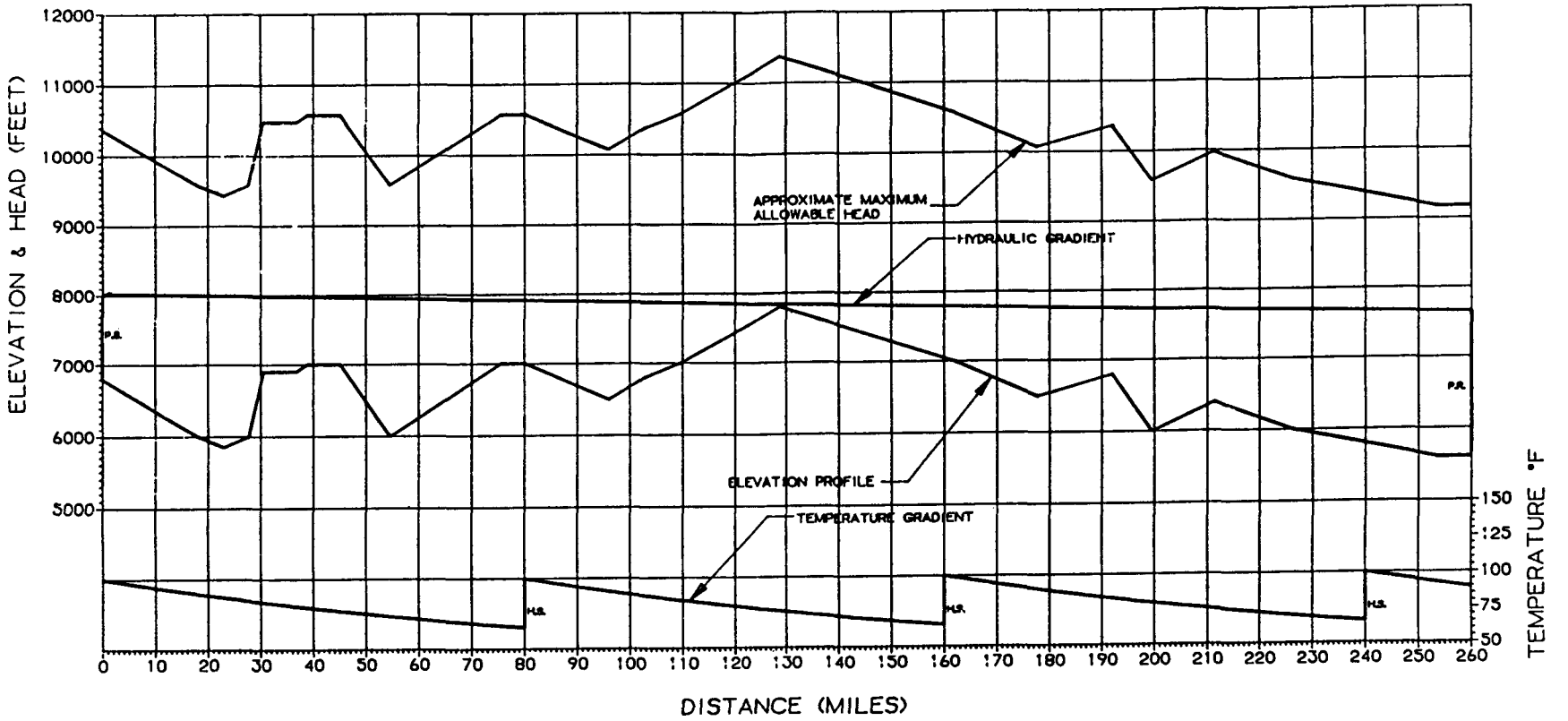
Laboratory data on liquid bulk modulus is required to calculate surge pressures and pressue wave travel velocity. Since shale oil in properties differ somewhat from other hydrocarbon liquids, the bulk modulus variations with pressure and temperature should be explored sufficiently to establish their pattern.



NOTES:
P.S. - PUMP STATION
P.R. - PRESSURE REDUCING STATION
H.S. - HEATER STATION

WILLIAMS BROTHERS ENGINEERING COMPANY A Resource Sciences company TULSA, OKLAHOMA	OCCIDENTAL OIL SHALE, INC. RETORT TO CASPER, WYOMING 20" PIPELINE - 6" INSULATION INLET TEMPERATURE - 100°F FLOWRATE - 7,500 STBOPD	
	Date 9-80 Approved	EXHIBIT 8-1

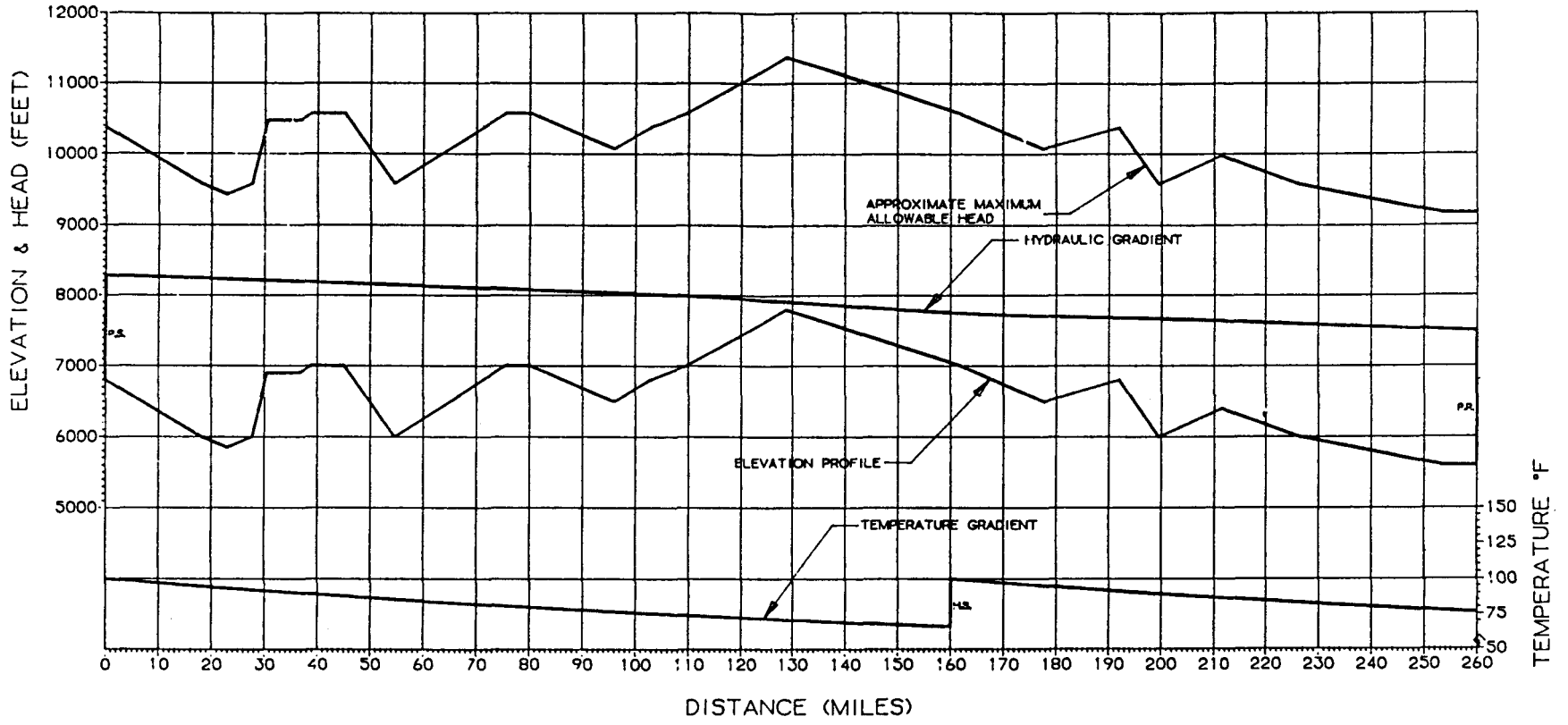
DATE PLOTTED 10-3-80



NOTES:
P.S. - PUMP STATION
P.R. - PRESSURE REDUCING STATION
H.S. - HEATER STATION

WILLIAMS BROTHERS ENGINEERING COMPANY A Resource Sciences company TULSA, OKLAHOMA	OCCIDENTAL OIL SHALE, INC. RETORT TO CASPER, WYOMING 20" PIPELINE - 6" INSULATION INLET TEMPERATURE - 100°F FLOWRATE - 15,000 STBOPD	
	Date 9-80 Approved	EXHIBIT E

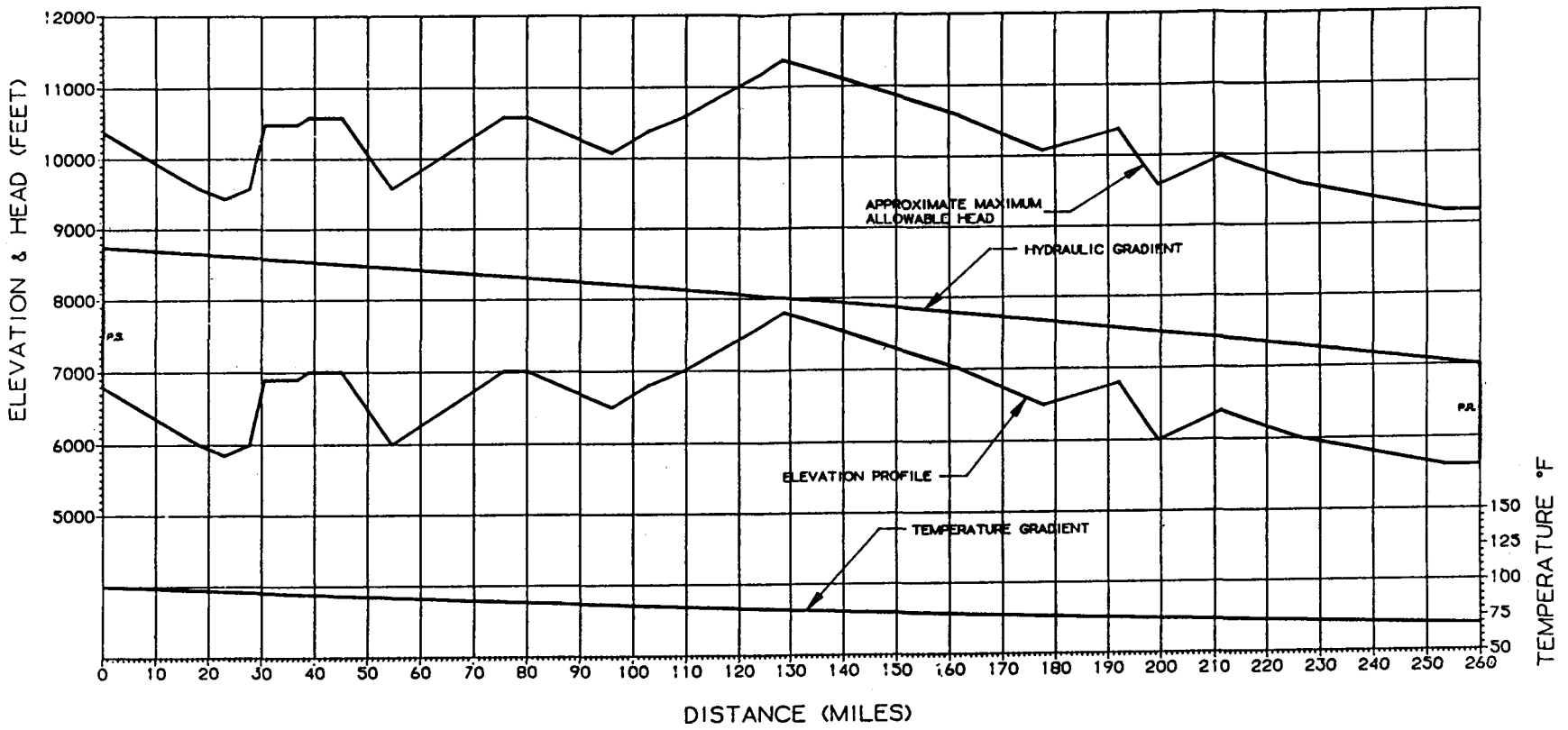
DATE PLOTTED 10-3-80



NOTES:
P.S. - PUMP STATION
P.R. - PRESSURE REDUCING STATION
H.S. - HEATER STATION

WILLIAMS BROTHERS ENGINEERING COMPANY A Resource Sciences company TULSA, OKLAHOMA	OCCIDENTAL OIL SHALE, INC. RETORT TO CASPER, WYOMING 20" PIPELINE - 6" INSULATION INLET TEMPERATURE - 100°F FLOWRATE - 30,000 STBOPD
Date 9-80 Approved	EXHIBIT 8-3

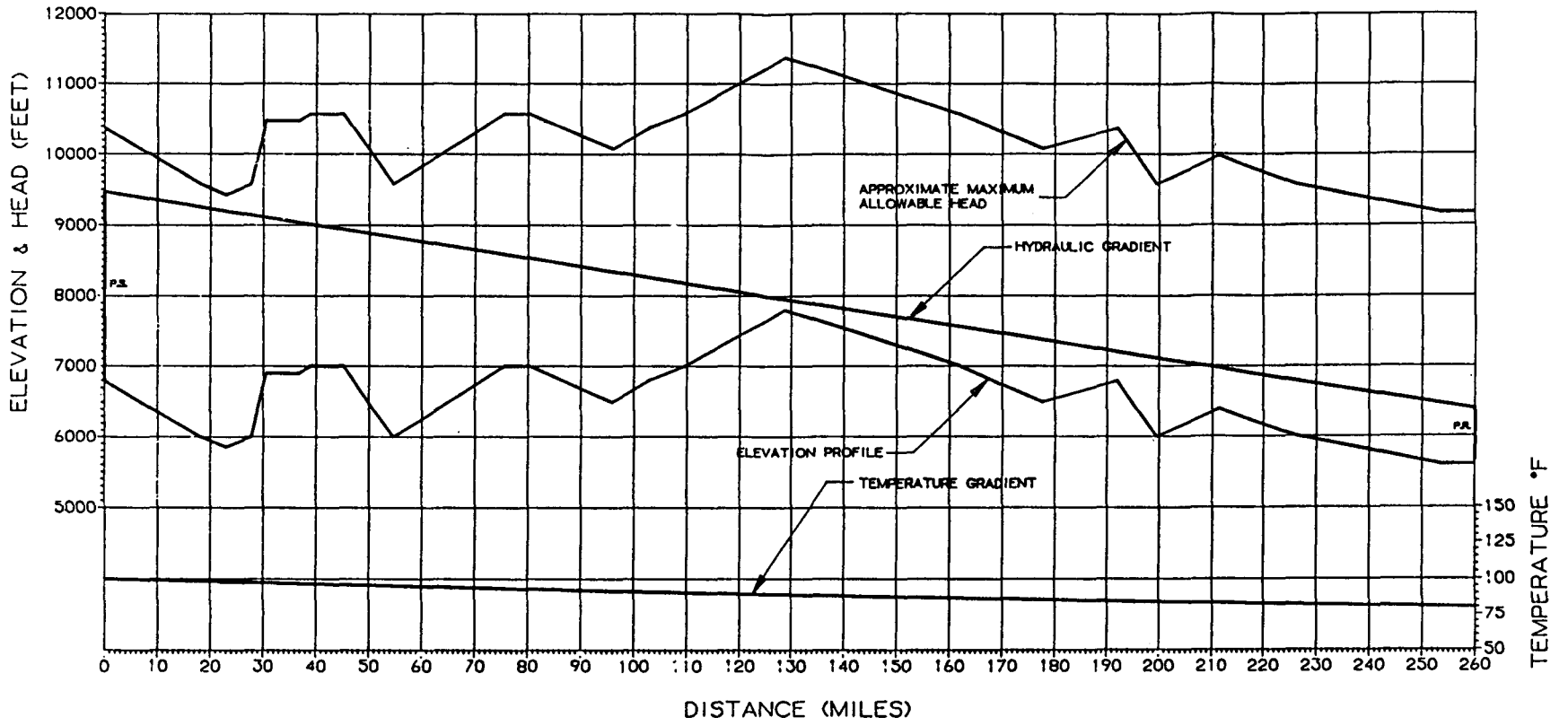
DATE PLOTTED 10-3-80



NOTES:
P.S. - PUMP STATION
P.R. - PRESSURE REDUCING STATION

WILLIAMS BROTHERS ENGINEERING COMPANY A Resource Sciences company TULSA, OKLAHOMA	OCCIDENTAL OIL SHALE, INC. RETORT TO CASPER, WYOMING 20" PIPELINE - 6" INSULATION INLET TEMPERATURE - 100°F FLOWRATE - 50,000 STBOPD	
	Date 9-80 Approved	EXHIBIT 8

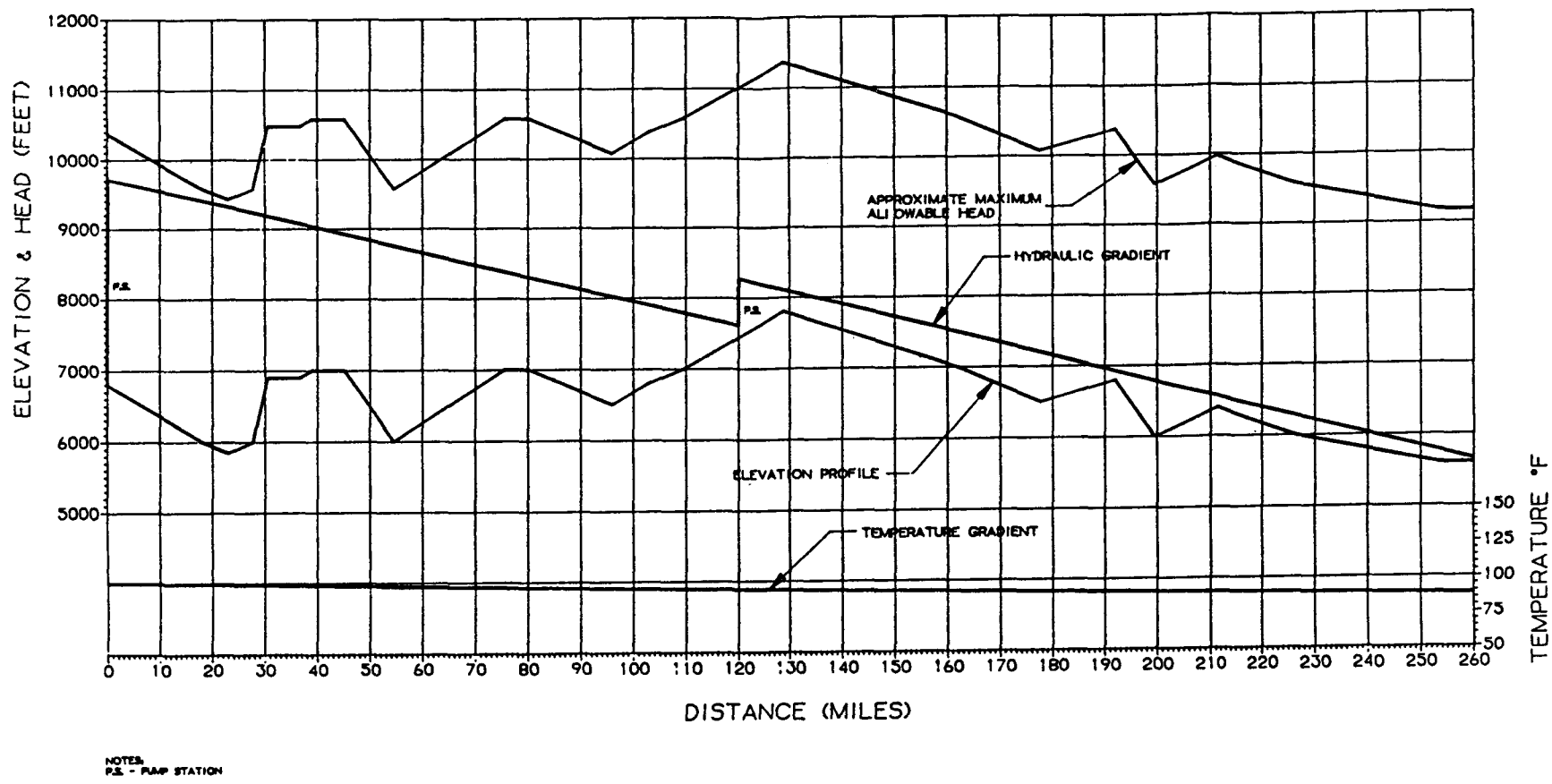
DATE PLOTTED 10-3-80



NOTES:
P.S. - PUMP STATION
P.R. - PRESSURE REDUCING STATION

WILLIAMS BROTHERS ENGINEERING COMPANY A Resource Sciences company TULSA, OKLAHOMA	OCCIDENTAL OIL SHALE, INC. RETORT TO CASPER, WYOMING 20" PIPELINE - 6" INSULATION INLET TEMPERATURE - 100°F FLOWRATE - 75,000 STBOPD
Date 9-80 Approved	EXHIBIT 8-5

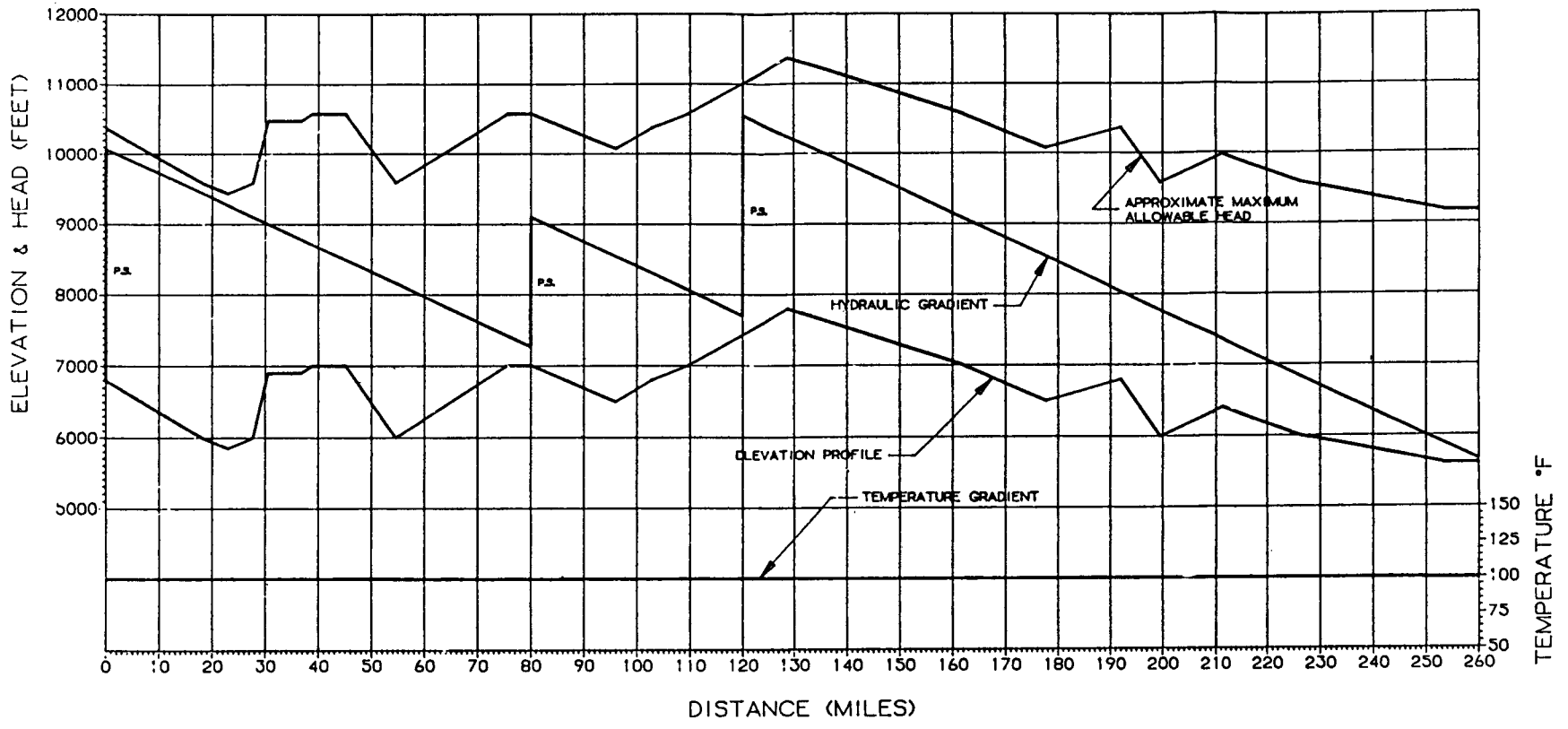
DATE PLOTTED 10-3-80



NOTES:
P.S. - PUMP STATION

WILLIAMS BROTHERS ENGINEERING COMPANY A Resource Sciences company TULSA, OKLAHOMA	OCCIDENTAL OIL SHALE, INC. RETORT TO CASPER, WYOMING 20" PIPELINE - 6" INSULATION INLET TEMPERATURE - 100°F FLOWRATE - 100,000 STBOPD
Date 9-80 Approved	EXHIBIT 8-6

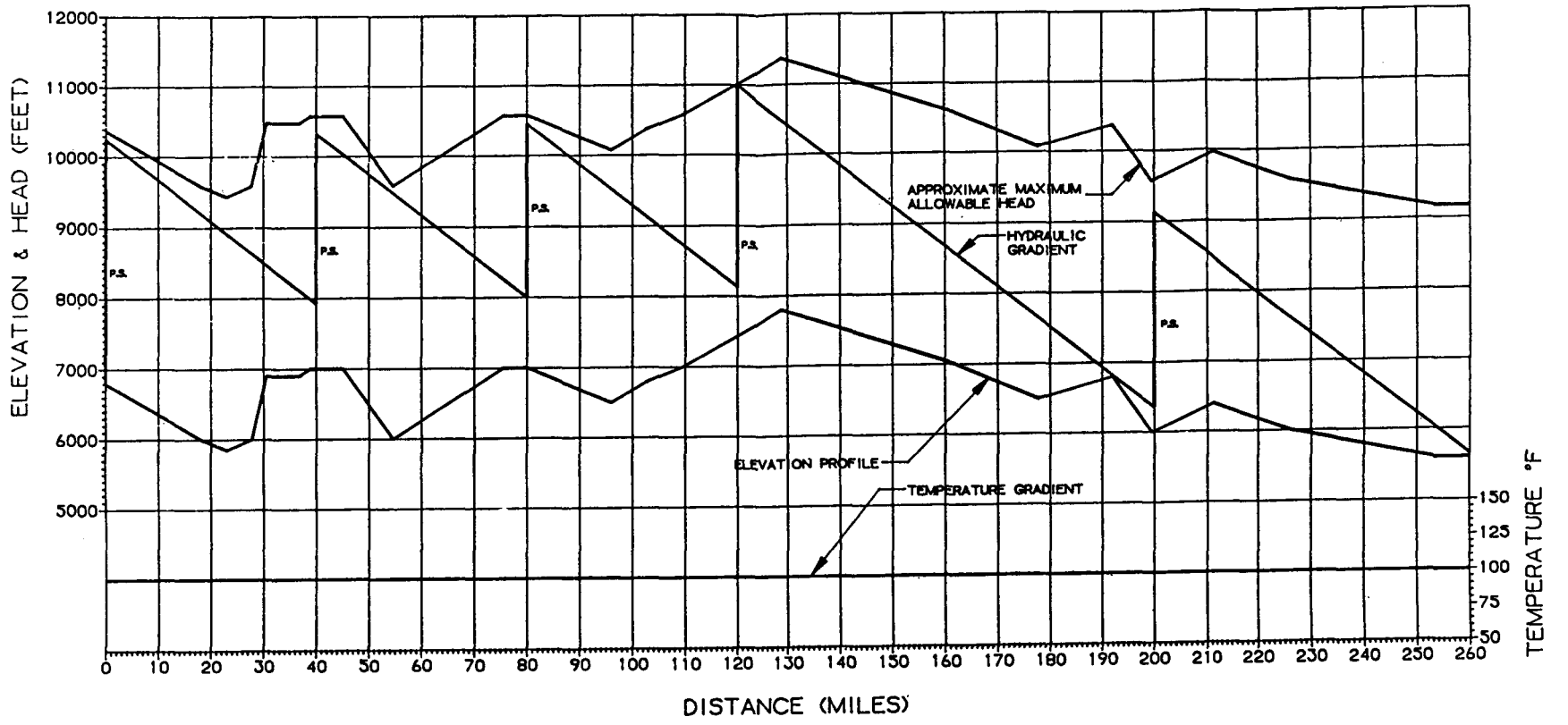
DATE PLOTTED 10-3-80



NOTES
P.S. - PUMP STATION

WILLIAMS BROTHERS ENGINEERING COMPANY A Resource Sciences company TULSA, OKLAHOMA	OCCIDENTAL OIL SHALE, INC. RETORT TO CASPER, WYOMING 20" PIPELINE - 6" INSULATION INLET TEMPERATURE - 100°F FLOWRATE - 150,000 STBOPD
	Date 9-80 Approved
	EXHIBIT 8-7

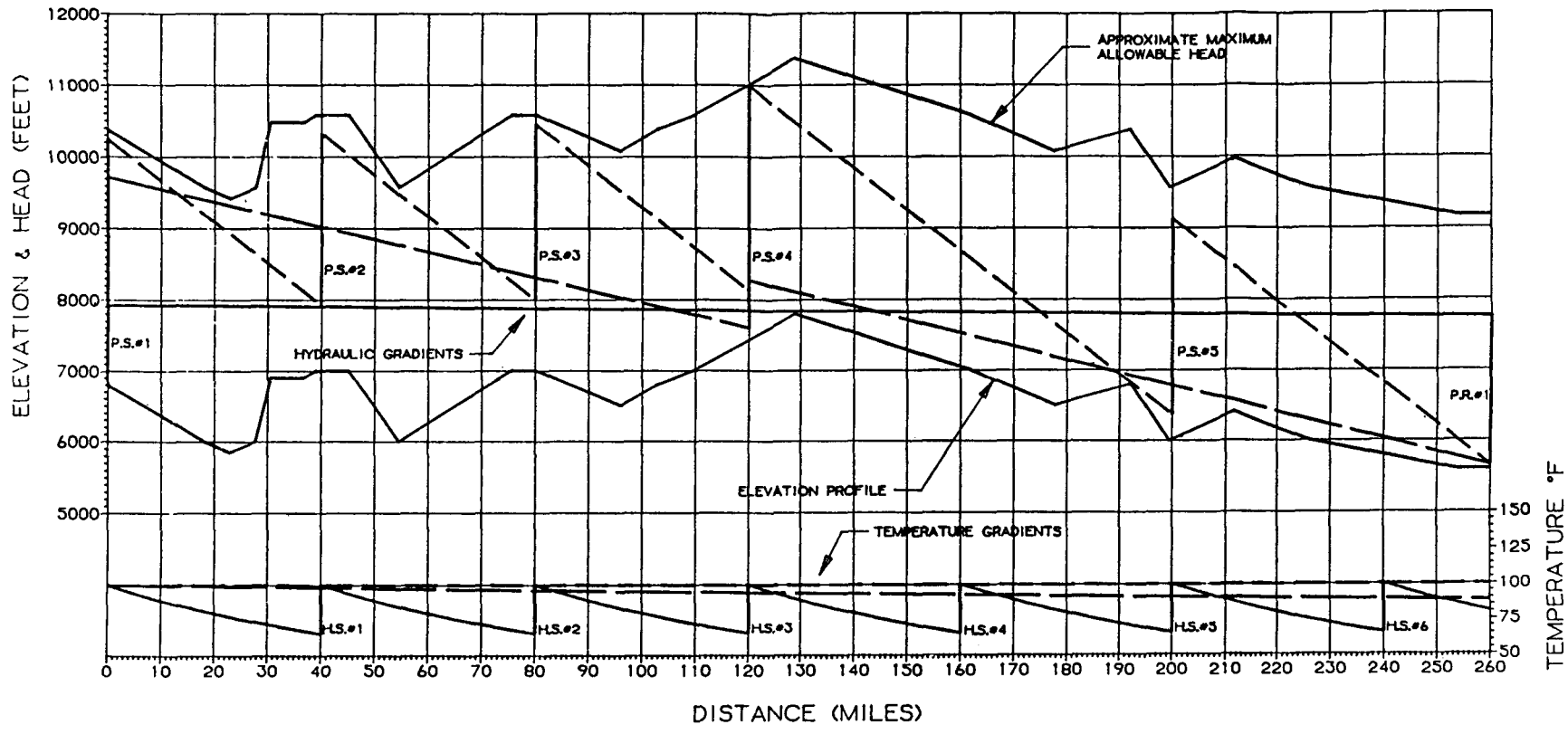
DATE PLOTTED 10-3-80



NOTES:
P.S. - PUMP STATION

WILLIAMS BROTHERS ENGINEERING COMPANY A Resource Sciences company TULSA, OKLAHOMA	OCCIDENTAL OIL SHALE, INC. RETORT TO CASPER, WYOMING 20" PIPELINE - 6" INSULATION INLET TEMPERATURE - 100°F FLOWRATE - 200,000 STBOPD	
	Date 9-80 Approved	EXHIBIT 8-(

DATE PLOTTED 10-3-80



NOTES.
P.S. - PUMP STATION
P.R. - PRESSURE REDUCING STATION
H.S. - HEATER STATION

FLOWRATE - 7,500 STBOPD

FLOWRATE - 100,000 STBOPD

FLOWRATE - 200,000 STBOPD

WILLIAMS BROTHERS ENGINEERING COMPANY
A Resource Sciences company
TULSA, OKLAHOMA

OCCIDENTAL OIL SHALE, INC.
20" PIPELINE - 6" INSULATION
INLET TEMPERATURE - 100°F
FLOWRATE - VARIOUS

Date 10-80
Approved

EXHIBIT 8-9

DATE PLOTTED 10-16-80

9. ECONOMIC EVALUATION

For estimating cost versus pipe size, insulation thickness and heating, the basic assumptions are:

1. Design flow rate is 100,000 BPD.

2. Heating and pressure reducing stations are included to operate at flow rates of 7,500 to 100,000 BPD.

3. Additional pump stations for 150,000 and 200,000 BPD are added only for those cases.

4. Pump station locations are compatible with future expansion to 200,000 BPD.

5. Investment for general facilities including offices, maintenance facilities, communications and supervisory control are included.

6. Operating expense estimates are calculated for each flow rate.

For purposes of comparison, estimated costs of transportation service are developed for each flow rate. Estimated investment is valued at the present value of equal annual payments over the assumed project life of 20 years for debt retirement with an assumed rate of interest. Present value is calculated using an assumed discount rate.

Exhibit 9-1 shows estimated unit cost of transportation versus flow rate on the premises described above. The investment in heating stations is included at all flow rates even though the heaters are only used at lower flow rates.

Each annual payment, A, to retire investment, I, in n years with an interest rate, i, compounded annually is:

$$A = \frac{Ii}{1 - (1 + i)^{-n}}$$

The sum, S, of the present values of the n annual payments at discount rate, d, is:

$$S = \frac{A\left[1 - (1 + d)^{-n}\right]}{D}$$

Using the values:

Interest rate, i = 0.12

Number of annual payments, n = 20

Discount rate, d = 0.14

this sum is:

$$S = 0.8867 \times I$$

Operating expenses are taken at a constant annual rate. This assumes that the value of money changes inversely as current costs change over the life of the project. No consideration is given to depreciation or taxes.

The cost per barrel of transportation service is equal to the sum of the present value of investment payments plus operating expenses for the project life divided by the total barrels delivered for that number of years at a constant flow rate.

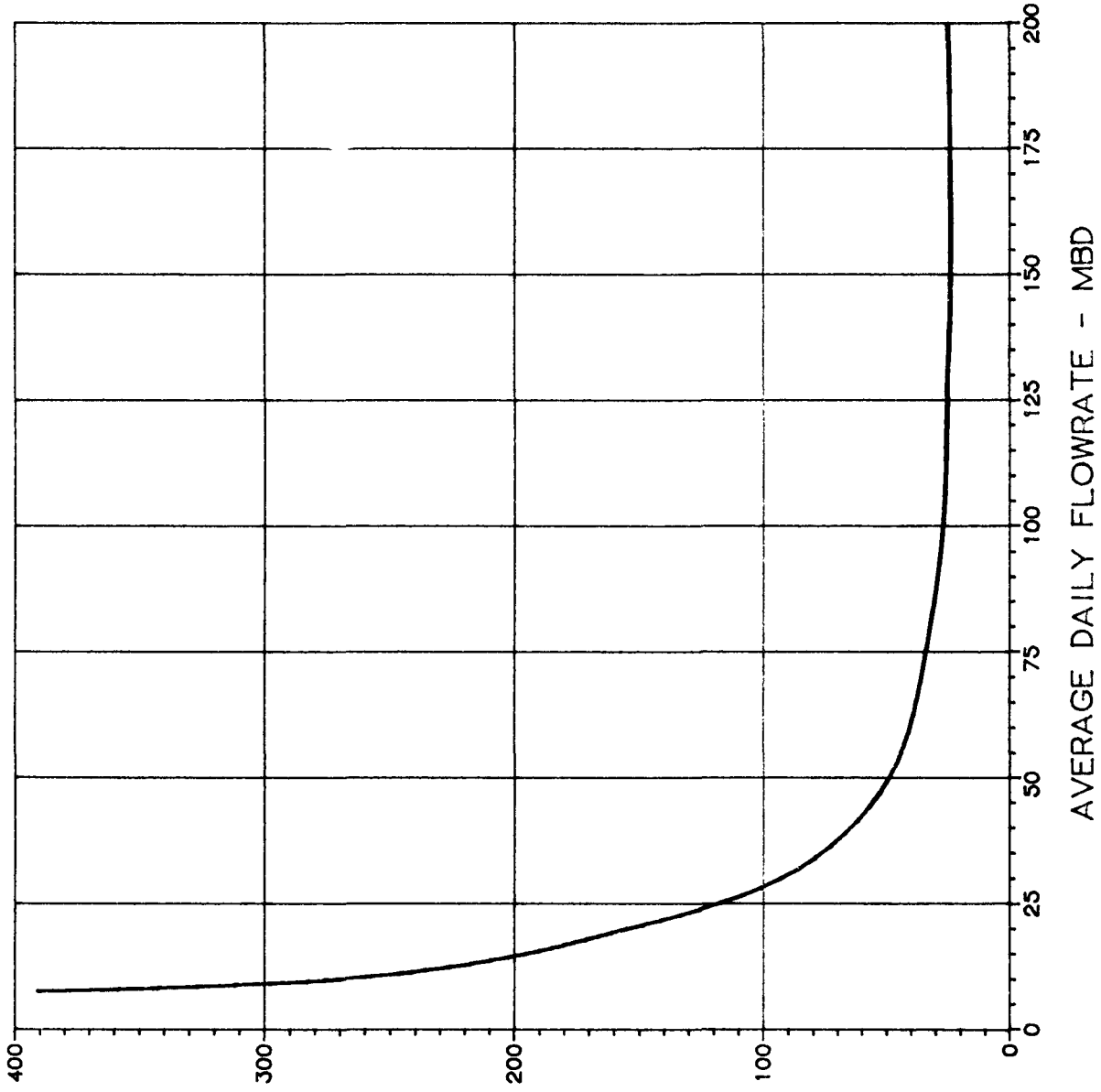
The following table compares the unit transportation cost of service for different pipe sizes at a flow rate of 100,000 BPD. For each pipe size various insulation thicknesses are included in the analyses; however, only results for the optimum thickness are tabulated here.

Nominal Pipe Size	Opt. Insul Thickness in.	Est. Investment ($1,000's)	Est. Annual Oper. Exp. ($1,000's)	Cost of Service ¢/BBL
12"	1"	106,850	15,250	54.8
14"	2"	104,600	9,810	39.6
16"	4"	109,300	5,990	29.7
18"	4"	121,700	4,270	26.5
20"	4"	136,950	3,390	25.9
20"	6"	143,610	3,310	26.5
24"	4"	162,320	2,790	27.4

Note: Above number do not include investment for heating stations required for flow rates below 100,000 BBL per day.

The minimum cost of service is a 20" pipeline with 4" insulation thickenss. Pump station locations in the 20" system have been selected to be compatible with future locations required for expansion to a 200,000 BPD flow rate. For the 20" pipeline, the unit costs for 6" insulation are not significantly higher than those for 4" thickness so that the thicker insulation would be preferred because it provides a slower cool down.

Heater fuel costs of $40 per barrel and electric power costs of 4.5 cents per kilowatt-hour are assumed for the operating expense estimates.



NOTE - COSTS EXCLUDE TAXES, ROYALTIES, PROFIT, AND DEPRECIATION

WILLIAMS BROTHERS ENGINEERING COMPANY

A Resource Sciences company

TULSA, OKLAHOMA

ESTIMATED TRANSPORTATION COSTS
VS. AVERAGE FLOWRATE
20" PIPE - 6" THICK INSULATION
SHALE OIL PIPELINE
OCCIDENTAL OIL SHALE, INC.

Date 10-80

Approved

EXHIBIT 9-1

APPENDIX NO. 1

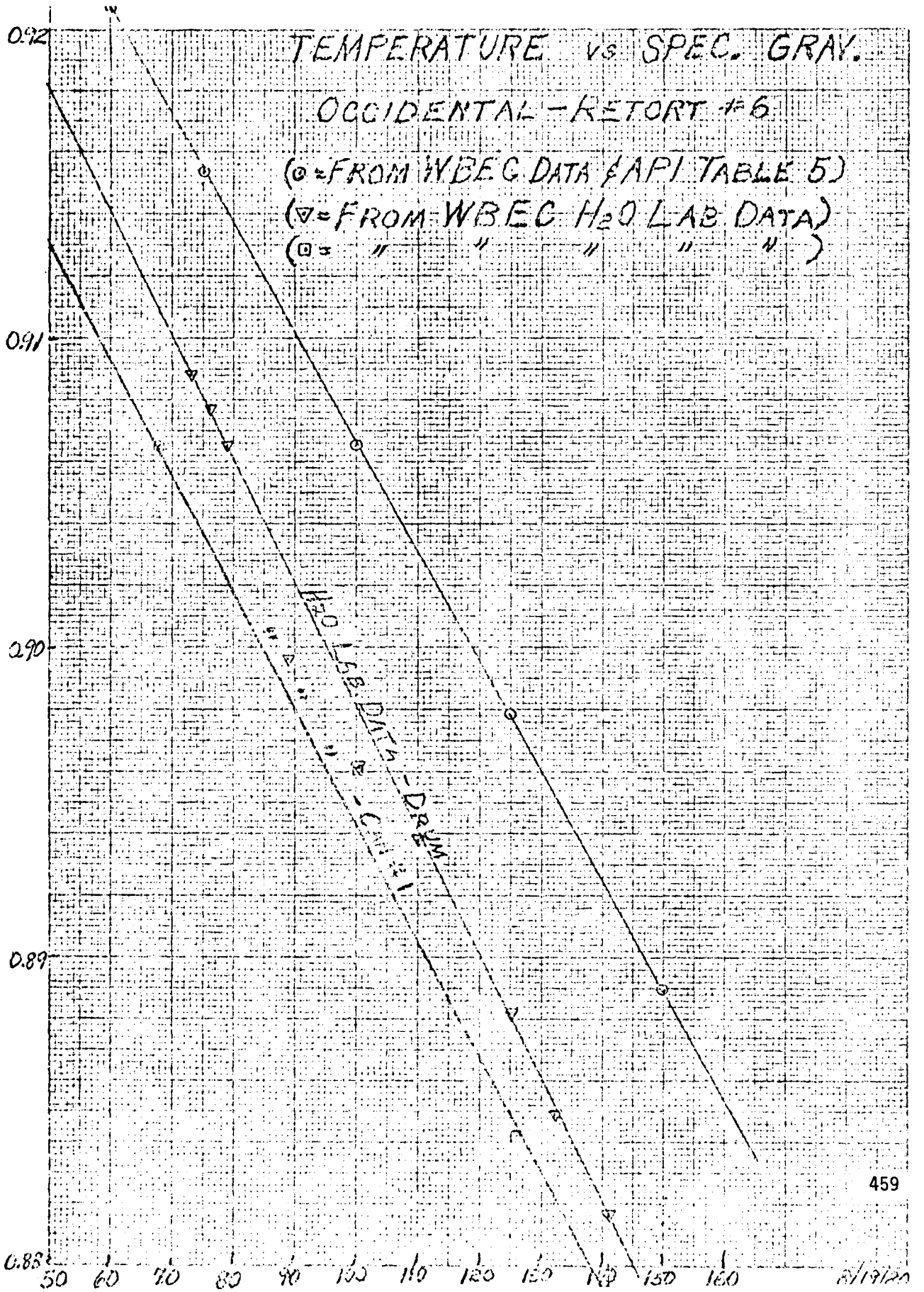
OCCIDENTAL SHALE OIL

RETORT NO. 6

SPECIFIC GRAVITY AND

ENTHALPY TEST DATA

August and November, 1980


TEMPERATURE vs SPEC. GRAV.
OCCIDENTAL - RETORT #6
(@ = FROM WBEC DATA & API TABLE 5)
(▽ = FROM WBEC H2O LAB DATA)
(□ = " " " " ")
0.92
0.91
0.90
0.89
0.88
50
60
70
80
90
100
110
120
130
140
150
160
H2O LAB DATA - DRUM
" " - CORE #1
8/19/20

CHROMASPEC CORP.
(P-V-T)

[illegible] out of the 10-1
[illegible] sent to us by
Accidental - probably from
Can #1. Samples were from
RT #6. #24
11/20/80

Final Report

Enthalpy - Temperature Measurements on Shale Oil Sample

Enthalpy - temperature measurements were made on a shale oil sample furnished by Williams Brothers Engineering Company, Tulsa, Oklahoma. The sample was taken as received.

Experimental and Results

Specific heat measurements were made using a procedure essentially identical to ASTM D-2766-71 for specific heats of liquids and solids. Results are given in Table I.

The low temperature measurement begins during the transition o solid to liquid. This is shown in the relatively large enthalpy changes at low temperature. At 30°F. the sample appears to act as a single phase liquid with a smooth change in enthalpy with temperature. The specific heat has been expressed as a function of temperature by a linear equation for this portion of the measurements.

Tabular values of enthalpy versus temperature are also given in Table I. The enthalpy has been set at 0 at the lowest temperature and a linear change has been assumed over the temperature interval for measurements in the transition region.

A graphical representation of enthalpy versus temperature is given in Figure 1. The plotted enthalpy values are those given in Table I.

Respectfully submitted,

James M Berryman

James M. Berryman
Senior Research Chemist



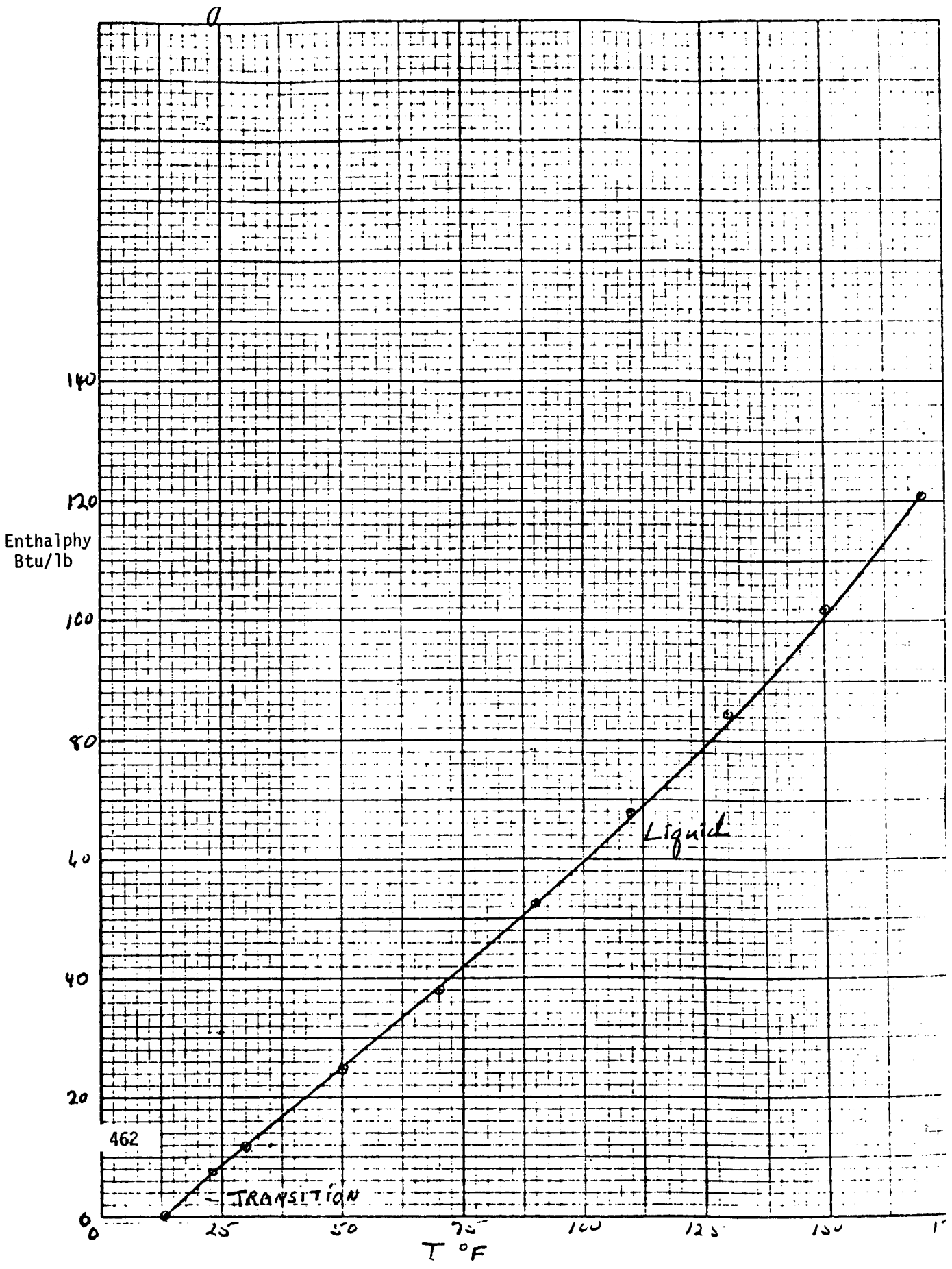
TABLE I. ENTHALPY - TEMPERATURE

Retort #6 Via Anvil Points Sample

Smoothed Enthalpy Change		Enthalpy (based on H=0 at 13°F)	
ΔT, °F.	ΔH, Btu/lb	T, °F	H, Btu/lb
13-23	7.83	13	0
23-30	4.12	23	7.83
30-50	12.47	30	11.95
50-70	13.49	50	24.42
70-90	14.52	70	37.91
90-110	15.54	90	52.43
110-130	16.56	110	67.97
130-150	17.58	130	84.53
150-170	18.61	150	102.11
		170	120.72

Heat capacity in Btu/lb/°F expressed as a function of temperature in °F by:

$$C_p = 0.519 + 0.00260\ t \qquad t > 30°F.$$


Enthalphy
Btu/lb
140
120
100
80
60
40
20
0
462
TRANSITION
Liquid
25
50
100
125
T °F

APPENDIX NO. 2

OCCIDENTAL SHALE OIL

RETORT NO. 6

POUR POINT AND VISCOSITY

TEST DATA

August, 1980 Series

"As Received Samples"

#4358

Date 7-31-80 Sample No. Retrieved to be Received

By WC Source Occidental 2nd Phase

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °C/F	Condition of Sample
0906	78°	Fluid
0930	72°	Fluid
0940	64°	Fluid
0955	58°	Fluid
1003	54°	Fluid
1020	49°	Fluid
1040	46°	Fluid
1053	44°	Fluid
1115	42°	Fluid
1320	40°	Fluid
1347	39°	Fluid
1420	37°	Fluid
1530	34°	Fluid
1700	32°	Slight movement
0900 8-1-80	31°	No movement

Ice box not cold enough

Water Bath

changed water to maintain before this

Sample taken from #1 can, Put in ice box first, was not cold enough so put sample in water bath, but the temp of the water bath was only about 30°C to start with. Water bath was not cold enough for sample to reach pour point waited

4358

Date 8-1-80 Sample No. Retort 6 As-Received

By W.C. Source Accidental 2nd Shot

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
1352	77°	Fluid
1400	74°	Fluid
1411	64°	Fluid
1415	59°	Fluid
1425	51°	Fluid
1432	46°	Fluid
1437	43°	Fluid
1442	40°	Fluid
1445	38°	No movement

2nd sample taken from same can. #1

Water bath temp. was about 20°C when sample was put in. Lowered temp. of bath to -8°C using a mixture of water & methanol.

Date 8-4-80 Sample No. Rotor 16-42 can

By WC Source Occidental

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °C/F	Condition of Sample	W.B. Temp.
0835	74°	Fluid	15.5
0905	68°	Fluid	10.0
0917	64°	Fluid	8.0
0929	60°	Fluid	6.0
0935	58°	Fluid	5.0
0940	56°	Fluid	4.0
0945	55°	Fluid	3.0
0953	53°	Fluid	2.0
1003	49°	No Movement	0.0

Sample taken from 16-42 can as received, put in water bath, temp. of W.B. was 15.5°C when sample was at

N. Lawler

Repeat

Date 8-4-80 Sample No. Retort-6-#2 can Occid

By W.C. Source Occidental

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample	W.B. temp
1310	76° F	Fluid	20.5 °C
1325	74°	Fluid	17.0
1340	71°	Fluid	17.0
1354	68°	Fluid	14.0
1416	64°	Fluid	10.0
1430	60°	Fluid	10.0
1455	56°	Fluid	11.0
1512	55°	Fluid	11.0
1525	54°	Slight movement	11.0
1603	53°	Slight movement	7.0
1615	52°	No movement	5.0

Same sample from #2 can, repeat test after temp. came up to 76°F / ambient room temp.

Date 8-5-80 Sample No. Rotella-#1-Sample

By W.C. Source Occidental

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample W.B. Temp
1355	77°	Fluid 0.0°C
1405	75°	Fluid
1417	64°	Fluid
1420	62°	Fluid
1424	60°	Fluid
1427	58°	Fluid
1433	54°	Fluid
1438	52°	no movement

1 of 3 samples taken from #1 can and put in waterbath at the same time to check pour points

Date 8-5-80 Sample No. Rt.6-#1-#3 com.

By W.C. Source Occidental

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
1355	77°	Fluid
1405	75°	Fluid
1418	62°	Fluid
1420	60°	Fluid
1425	58°	Fluid
1428	57°	Fluid
1433	55°	Fluid
1438	52°	Fluid
1445	50°	Fluid
1452	49°	Fluid
1457	48°	Fluid
1505	41.°	Slight movement
1520	45°	slight movement
1533	44°	no movement

W.S. temp 0.°C

1 of 3 samples taken from #1 can to check pour points

Date 8-5-80 Sample No. Pt. 6 - #1 - #2 cans

By W.C. Source Occidental

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
1355	77°	Fluid
1405	75°	Fluid
1418	64°	Fluid
1420	62°	Fluid
1424	60°	Fluid
1427	58°	Fluid
1433	55°	Fluid
1438	52°	no movement

NPS Engr. 0. °C

1693 sample taken from #1 can to check pourpoints

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 1358 | DATE 8-8-80

PREPARED BY W.C.

SYSTEM B-cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS
NOMINAL — % | ACTUAL — %

TEMPERATURE
BEFORE 75.2 °F 24 °C | AFTER 76.5 °F 24.7 °C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				Ret. 6-#1-As Received
2				
3				
4				
5	3.8	3.4		
6	5.1	4.5		Surface Soil Looks To Be
7	6.5	5.7		emulsified after Start of Test.
8	8.1	7.2		
9	10.1	9.1		
10	12.8	11.6		
11	17.6	16.3		
12	22.8	21.6		
13	29.0	28.0		
14	37.7	37.1		
15	48.8			

DRY CUPS

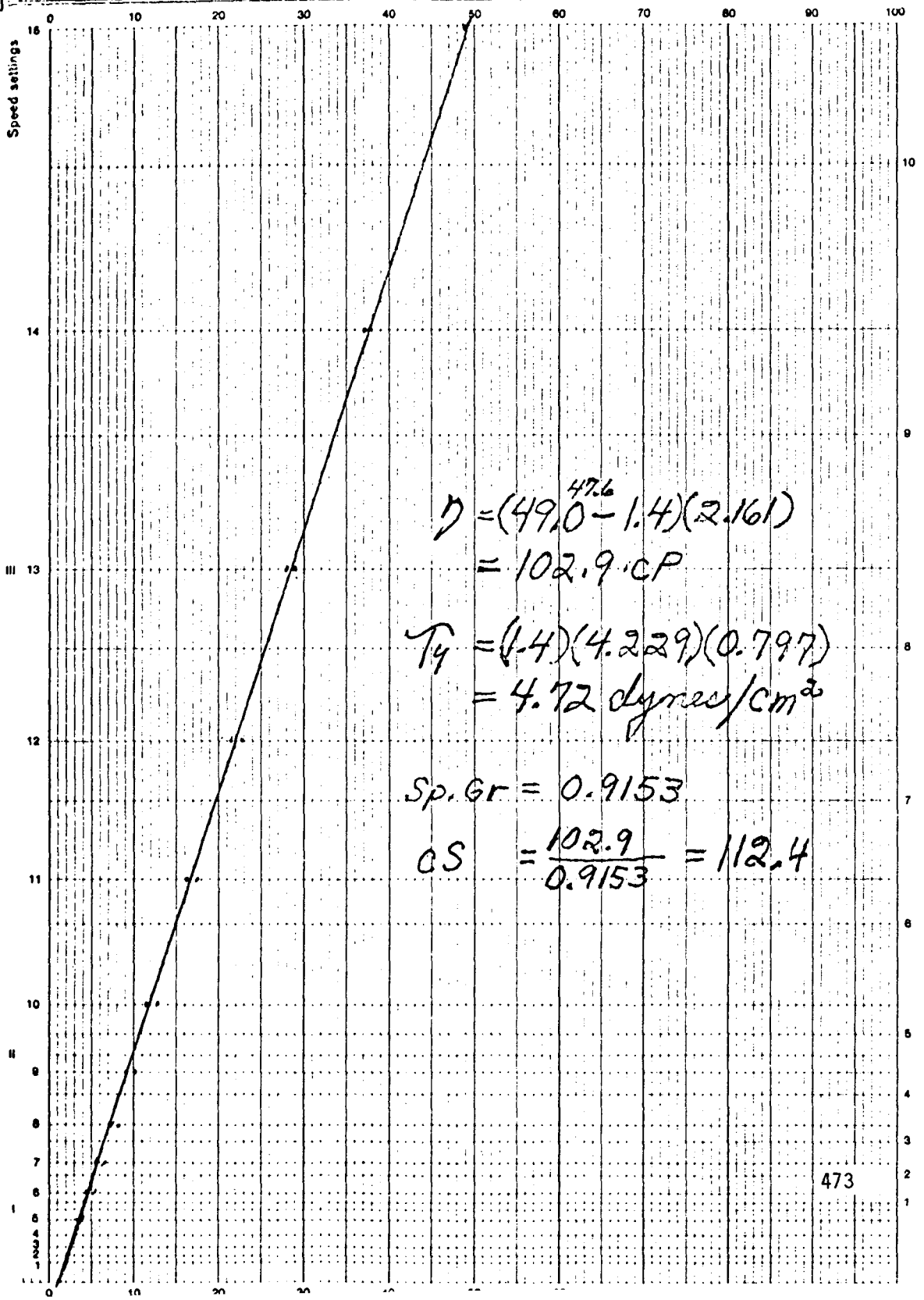
BEFORE		AFTER	
TIME PLACED IN OVEN:	☐AM ☐PM	TIME PLACED IN OVEN:	☐AM ☐PM
GROSS SLURRY WEIGHT	_____ GMS	GROSS SLURRY WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SLURRY WEIGHT	_____ GMS	NET SLURRY WEIGHT	_____ GMS
GROSS SOLID WEIGHT	_____ GMS	GROSS SOLID WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SOLID WEIGHT	_____ GMS	NET SOLID WEIGHT	_____ GMS
472			
NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.	

BLU-200

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL B CUP			HLL	8/8/80
AS REC'D		75.2-76.5°F	SHALE OIL - RET. #6	



$$\eta = (49.0^{47.6} - 1.4)(2.161)$$
$$= 102.9 \text{ cP}$$

$$\tau_y = (1.4)(4.229)(0.797)$$
$$= 4.72 \text{ dynes/cm}^2$$

$$\text{Sp. Gr} = 0.9153$$

$$\text{CS} = \frac{102.9}{0.9153} = 112.4$$

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 135-8 | DATE 8-8-50

PREPARED BY W.C.

SYSTEM A-Cup

MATERIAL Shale oil

SOURCE Occidental

ADDITIVES —

WEIGHT PER CENT SOLIDS

NOMINAL — % | ACTUAL — %

TEMPERATURES

BEFORE 100°F = 37.9 °C | AFTER 97°F = 37.2 °C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				Ref. 6-1-1 - As Received
2				
3	3.4	3.2	3.3	
4	4.2	4.3	4.25	
5	5.6	5.7	5.65	
6	8.2	8.3	8.25	
7	11.1	11.2	11.15	
8	14.7	14.8	14.75	
9	19.6	19.8	19.7	
10	25.9	26.1	26.0	
11	38.0	38.2	38.1	
12	51.5	51.7	51.6	
13	68.5	68.6	68.55	
14	92.6		92.6	
15	Off-Scale			

DRY CUPS

BEFORE

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

474

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

AFTER

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

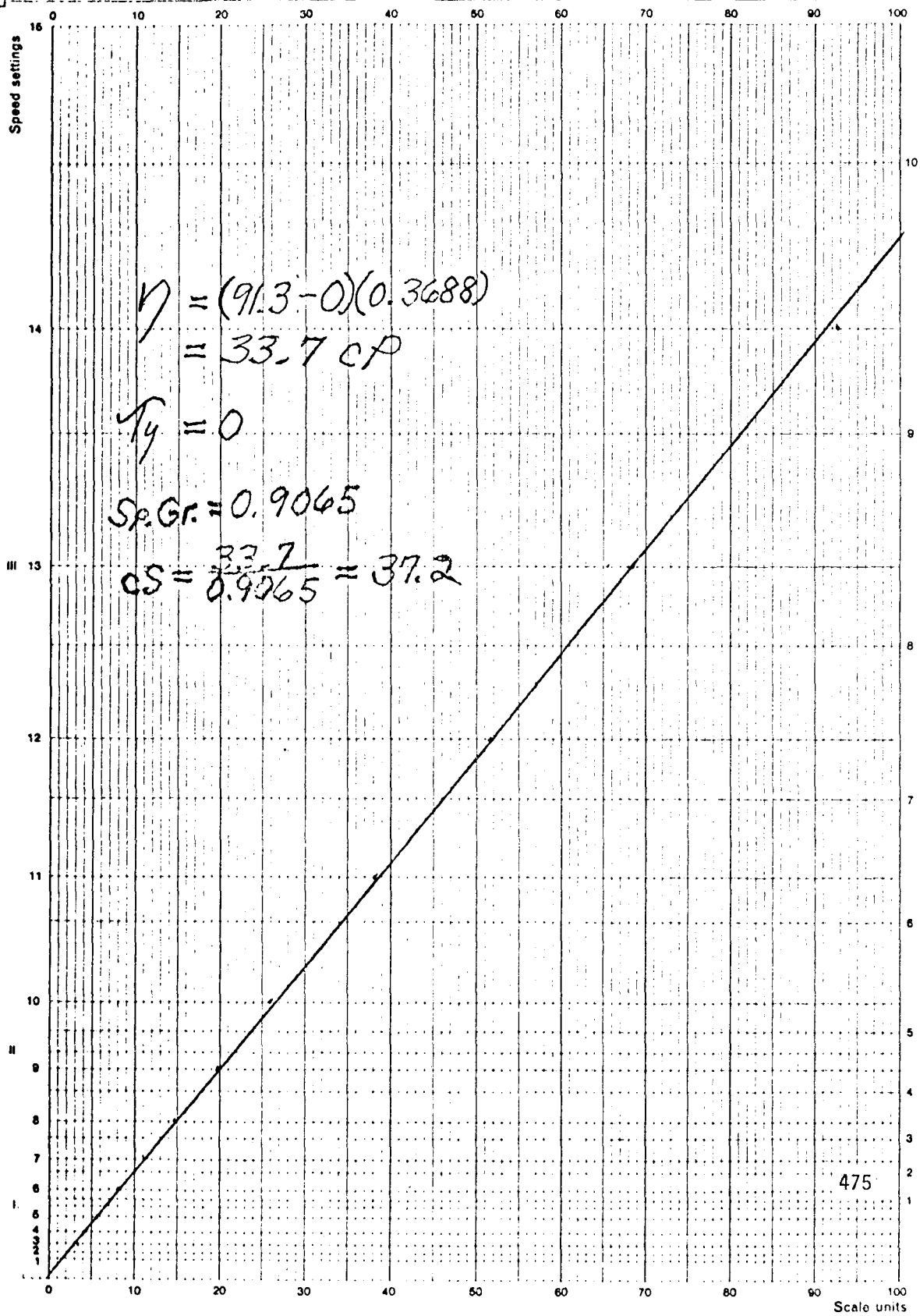
NET SOLID WEIGHT _____ GMS

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL	A CUP		HLL	8/8/80
AS REC'D		99-100	SHALE OIL-RET. #6	



$\eta = (91.3-0)(0.3688)$

$= 33.7$ cP

$\tau_y = 0$

Sp. Gr. $= 0.9065$

$cS = \frac{33.7}{0.9065} = 37.2$

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 8-8-80

PREPARED BY W.C.

SYSTEM A-Cup

MATERIAL Black Oil

SOURCE Occidental

ADDITIVES —

WEIGHT PER CENT SOLIDS: NOMINAL — % | ACTUAL — %

TEMPERATURES: BEFORE 126°F / 52.3°C | AFTER 126.5°F / 52.5°C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				Bottle #1-A Rejected
2				
3				
4				
5				
6	4.2	4.1	4.15	
7	5.7	5.6	5.65	
8	7.6	7.5	7.55	
9	10.2	10.0	10.10	
10	13.5	13.4	13.45	
11	19.8	19.7	19.75	
12	27.0	26.8	26.90	
13	36.1	35.9	56.00	
14	49.0	48.9	48.95	
15	66.0		66.00	

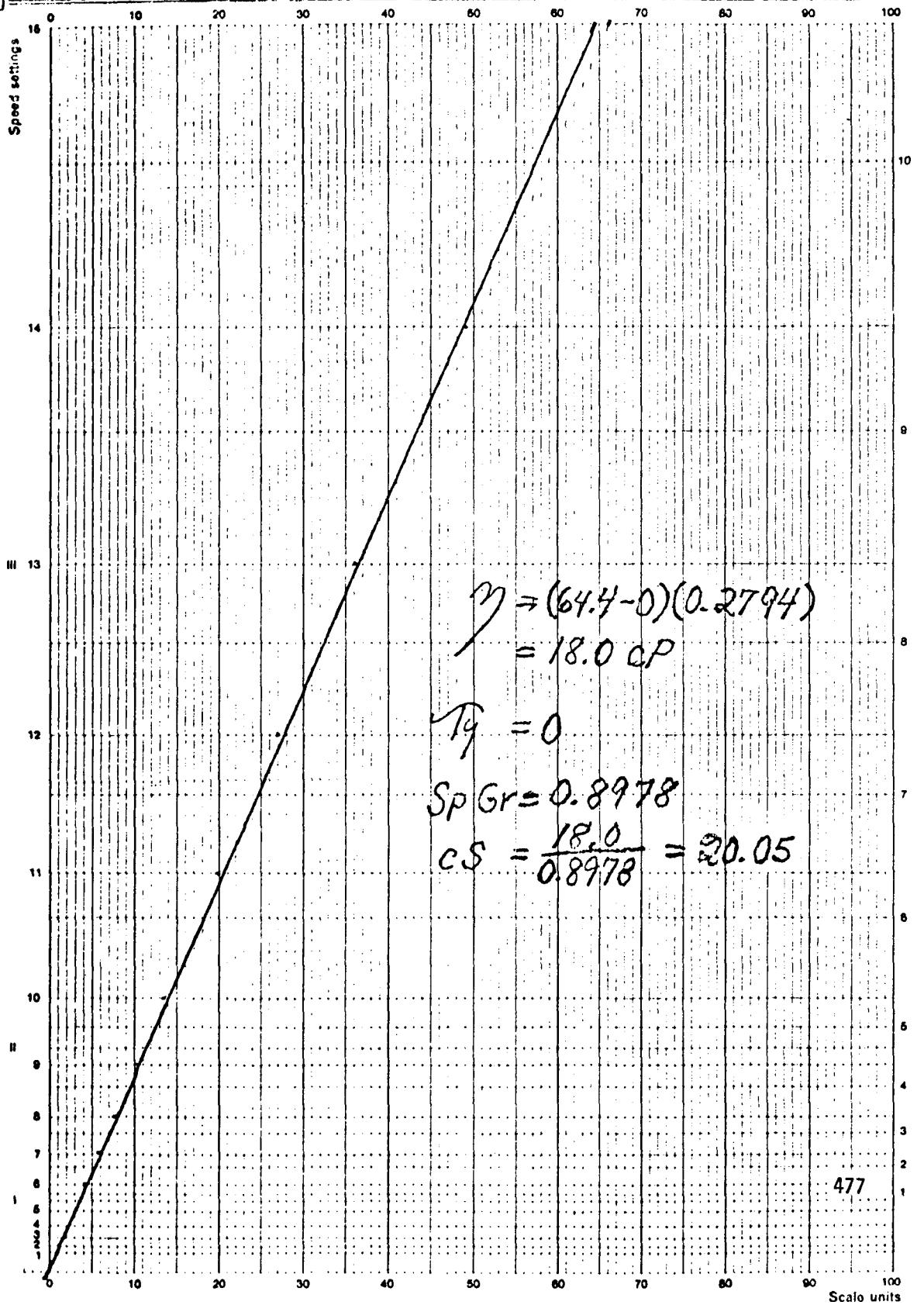
DRY CUPS

BEFORE	AFTER
TIME PLACED IN OVEN: ☐AM ☐PM	TIME PLACED IN OVEN: ☐AM ☐PM
GROSS SLURRY WEIGHT _____ GMS	GROSS SLURRY WEIGHT _____ GMS
LESS: CUP #___ TARE _____ GMS	LESS: CUP #___ TARE _____ GMS
NET SLURRY WEIGHT _____ GMS	NET SLURRY WEIGHT _____ GMS
GROSS SOLID WEIGHT _____ GMS	GROSS SOLID WEIGHT _____ GMS
LESS: CUP #___ TARE _____ GMS	LESS: CUP #___ TARE _____ GMS
NET SOLID WEIGHT _____ GMS	NET SOLID WEIGHT _____ GMS
476	
NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL	A-CUP		HLL	8/8/80
AS RECD		126.3 °F	SHALE OIL - RET. #6	



$\eta = (64.4-0)(0.2794)$

$= 18.0$ cP

$T_y = 0$

Sp Gr = 0.8978

$cS = \frac{18.0}{0.8978} = 20.05$

477

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 8-8-80

PREPARED BY W. C.

SYSTEM A - Cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES —

WEIGHT PER CENT SOLIDS
NOMINAL — % | ACTUAL — %

TEMPERATURES
BEFORE 149°F 65 °C | AFTER 149.5°F 65.3 °C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				Ret 6-11-80 As Received
2				
3				
4				
5				
6				
7	3.5	3.5	3.5	
8	4.7	4.7	4.7	
9	6.3	6.3	6.3	
10	8.4	8.5	8.45	
11	12.5	12.6	12.55	
12	17.2	17.2	17.2	
13	23.1	23.1	23.1	
14	31.6	31.7	31.65	
15	43.0		43.0	

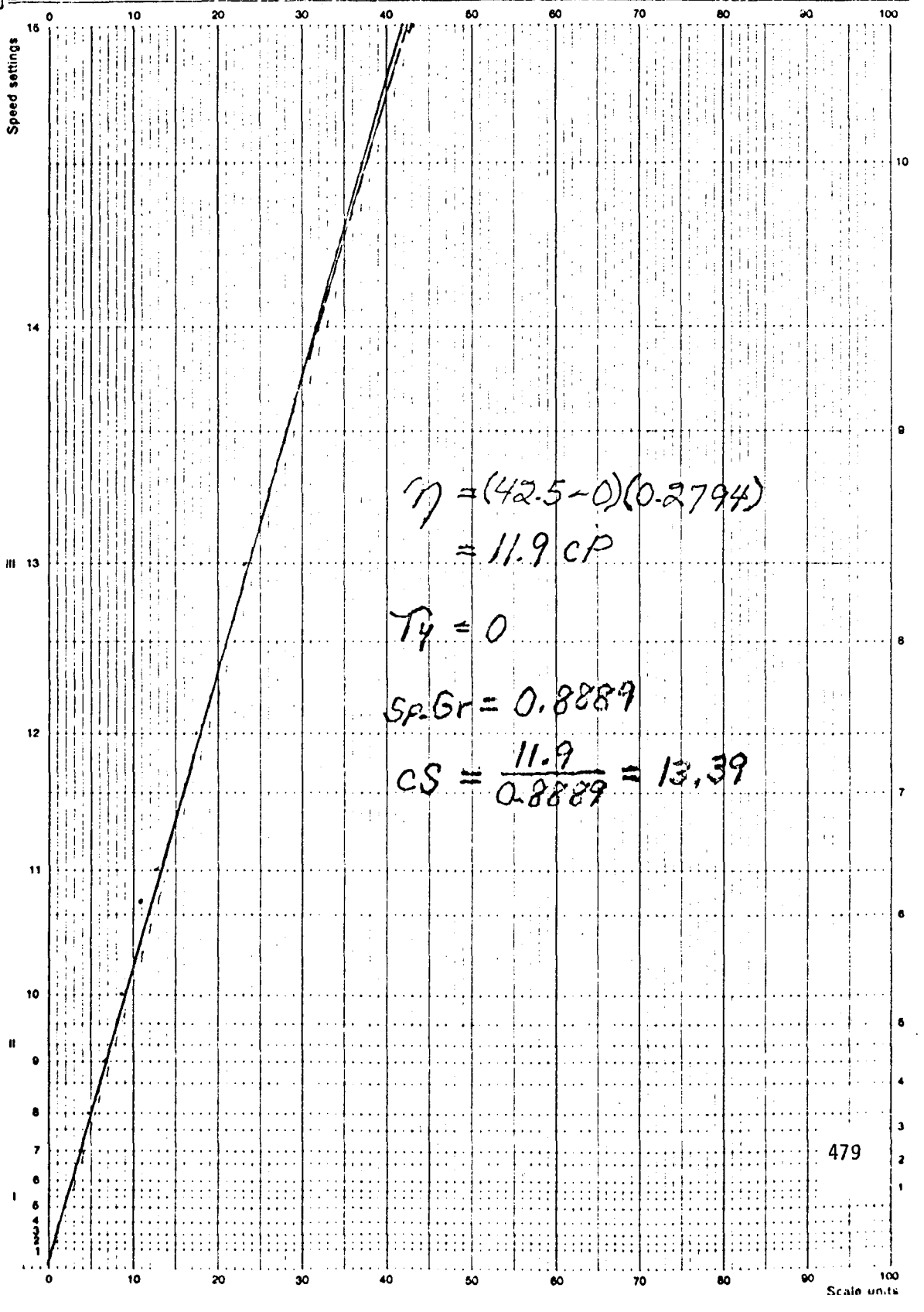
DRY CUPS

BEFORE			AFTER		
TIME PLACED IN OVEN:		☐AM ☐PM	TIME PLACED IN OVEN:		☐AM ☐PM
GROSS SLURRY WEIGHT		GMS	GROSS SLURRY WEIGHT		GMS
LESS: CUP #___ TARE		GMS	LESS: CUP #___ TARE		GMS
NET SLURRY WEIGHT		GMS	NET SLURRY WEIGHT		GMS
GROSS SOLID WEIGHT		GMS	GROSS SOLID WEIGHT		GMS
LESS: CUP #___ TARE		GMS	LESS: CUP #___ TARE		GMS
NET SOLID WEIGHT		GMS	NET SOLID WEIGHT		GMS
478					
NET SOLID WEIGHT / NET SLURRY WEIGHT	____ × 100 = ____	% WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	____ × 100 = ____	% WT.

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	FILE	NAME	DATE
OCCIDENTAL	A-CUP		HLL	8/8/80
ADDITIVE	CONCENTRATION	MATERIAL		
AS REC'D	1493	OIL SHALE - RET. #6		



$\eta = (42.5 - 0)(0.2794)$

$= 11.9$ cP

$Ty = 0$

Sp.Gr = 0.8889

$cS = \frac{11.9}{0.8889} = 13.39$

479

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. #358 | DATE 8-13-80

PREPARED BY W.C.

SYSTEM C-Cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS — NOMINAL ___ % | ACTUAL ___ %

TEMPERATURES BEFORE 47.3 °F 8.5 °C | AFTER 47.7 °F 8.7 °C

SPEED SET	UP	DOWN	~~AVERAGE~~ UP	Dow.	REMARKS
1	8.1	8.5	8.8	8.6	Rate 1" - Accepted
2	9.2	9.1	9.7	9.2	
3	10.4	9.8	10.3	9.8	
4	11.5	10.3	11.2	10.4	
5	12.7	11.1	12.1	11.1	
6	14.6	12.2	13.3	12.3	
7	16.7	13.8	14.8	13.8	
8	18.5	15.5	16.5	15.5	
9	20.8	17.9	18.5	17.7	
10	23.9	20.8	21.2	20.4	
11	29.6	26.0	26.6	25.3	
12	36.2	31.5	32.0	30.6	
13	42.6	38.0	38.5	37.0	
14	51.6	46.9	46.8	45.6	
15	58.4		56.8		

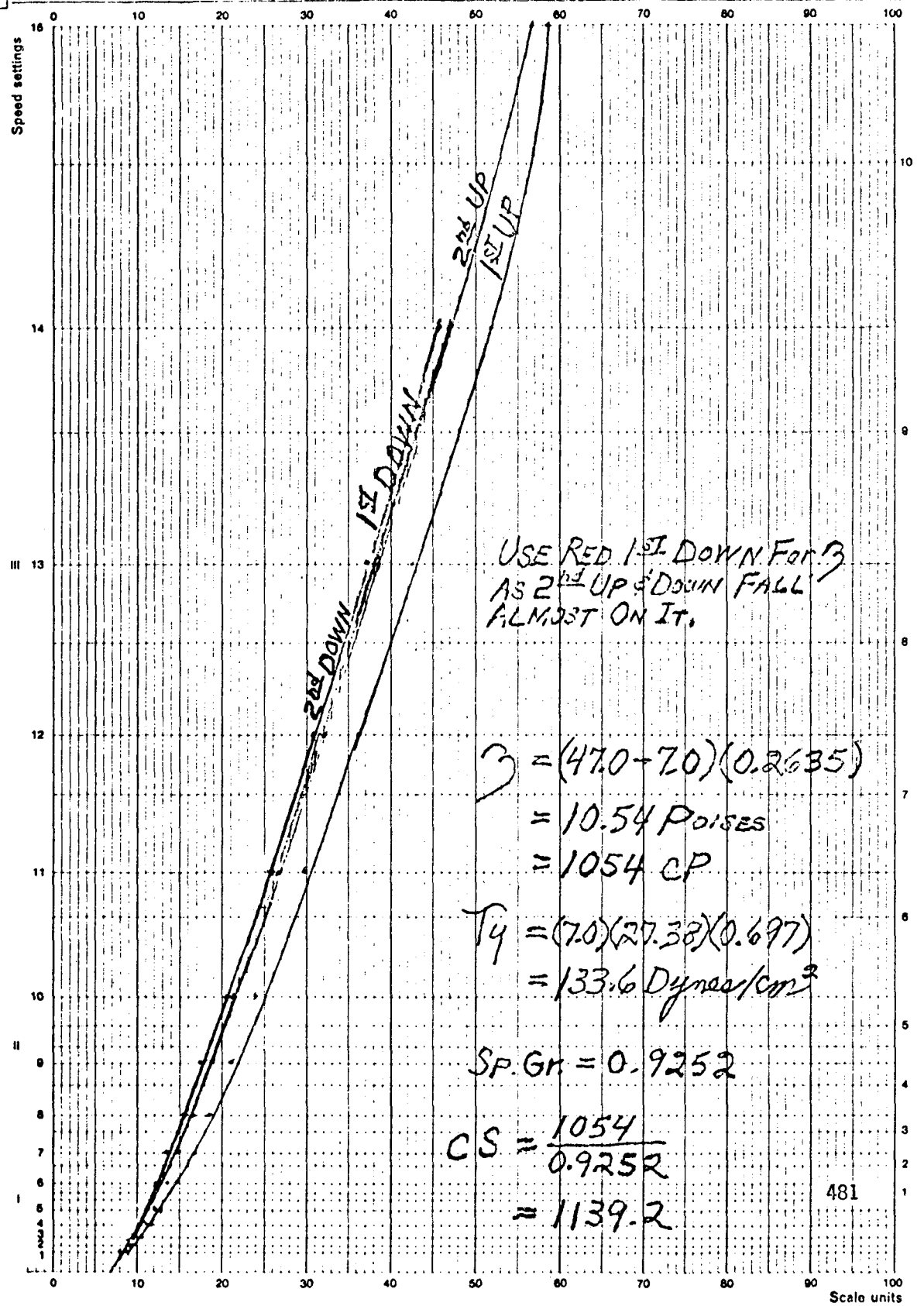
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN:	☐AM ☐PM	TIME PLACED IN OVEN:	☐AM ☐PM
GROSS SLURRY WEIGHT	___ GMS	GROSS SLURRY WEIGHT	___ GMS
LESS: CUP #___ TARE	___ GMS	LESS: CUP #___ TARE	___ GMS
NET SLURRY WEIGHT	___ GMS	NET SLURRY WEIGHT	___ GMS
GROSS SOLID WEIGHT	___ GMS	GROSS SOLID WEIGHT	___ GMS
LESS: CUP #___ TARE	___ GMS	LESS: CUP #___ TARE	___ GMS
NET SOLID WEIGHT	___ GMS	NET SOLID WEIGHT	___ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT ___ × 100 = ___ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT ___ × 100 = ___ % WT.	

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	PH	MAN	DATE
OCCIDENTAL C-CUP			HLL	8/13/80
ACTIVITY	CORE INTERVAL	MATERIAL		
AS REC'D	47.3-47.7	SHALE OIL-RET.#6		



WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO.	DATE
1358	8-13-50

PREPARED BY: W.C.

SYSTEM: C-Cup

MATERIAL: Shale Oil

SOURCE: Occidental Ave

ADDITIVES:

WEIGHT PER CENT SOLIDS — NOMINAL ___ % ACTUAL ___ %

TEMPERATURES — BEFORE 53.6 °F 12.0 °C — AFTER 53.6 °F 12.0 °C

SPEED SET	UP	DOWN	AVERAGE UP	AVERAGE DOWN	REMARKS
1	4.7	3.6	3.9	3.6	Rot 6-#1-No Liquid
2	5.2	3.9	4.3	3.9	
3	5.6	4.3	4.6	4.2	
4	6.4	4.6	5.1	4.6	
5	7.3	5.1	5.7	5.0	
6	8.8	5.9	6.5	5.8	
7	10.6	6.9	7.4	6.8	
8	12.5	8.1	8.5	7.9	
9	14.5	9.7	10.1	9.4	
10	16.2	11.7	12.1	11.2	
11	20.5	15.2	15.8	14.5	
12	24.2	19.0	19.6	18.1	
13	27.3	23.5	23.9	22.1	
14	32.4	29.8	29.8	28.5	
15	38.2		36.5		

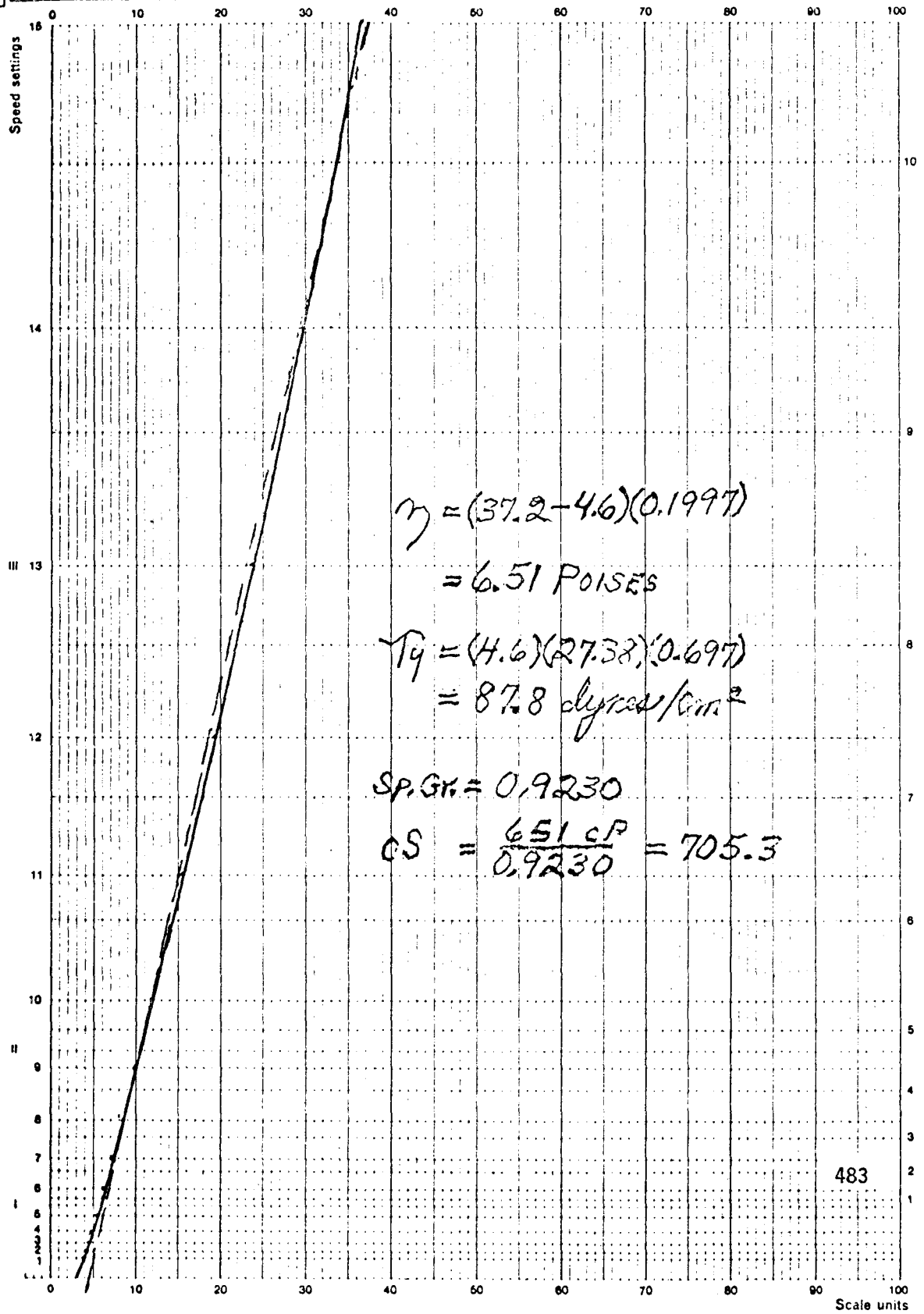
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	___ GMS	GROSS SLURRY WEIGHT	___ GMS
LESS: CUP #___ TARE	___ GMS	LESS: CUP #___ TARE	___ GMS
NET SLURRY WEIGHT	___ GMS	NET SLURRY WEIGHT	___ GMS
GROSS SOLID WEIGHT	___ GMS	GROSS SOLID WEIGHT	___ GMS
LESS: CUP #___ TARE	___ GMS	LESS: CUP #___ TARE	___ GMS
NET SOLID WEIGHT	___ GMS	NET SOLID WEIGHT	___ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT ___ × 100 = ___ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT ___ × 100 = ___ % WT.	

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL	C-CUP		HLL	8/13/80
AS REC'D	53.6 °F		SHALE OIL-RET.#6	



$\eta = (37.2 - 4.6)(0.1997)$

$= 6.51$ POISES

$\tau_q = (4.6)(27.38)(0.697)$

$= 87.8$ dynes/cm^2

Sp. Gr. = 0.9230

$CS = \frac{6.51\ cP}{0.9230} = 705.3$

APPENDIX NO. 3

OCCIDENTAL SHALE OIL

RETORT NO. 6

POUR POINT AND VISCOSITY

TEST DATA

August, 1980 Series

"Heated and Sheared Samples"

1 sample

Date 8-6-80 Sample No. B.T.L-H16-65°C

By W.C. Source Occidental

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °C/F	Condition of Sample
0900	94°	Fluid
0908	86°	Fluid
0916	79°	Fluid
0927	73°	Fluid
0942	69°	Fluid
0951	66°	Fluid
1005	63°	Fluid
1020	60°	Fluid
1032	58°	Fluid
1045	55°	Fluid
1100	52°	Fluid
1110	50°	Fluid
1121	48°	Fluid
1135	45°	Slight movement
1145	43°	no movement

Sample taken from #1 can, heated in oven overnight 16 hr. at 65°C or 150°F

#2 sample

Date 8-6-80 Sample No. Lub-H16-65°C

By W.C. Source Accidental

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
0900	93°	Fluid
0908	84°	Fluid
0916	77°	Fluid
0928	72°	Fluid
0942	68°	Fluid
0951	65°	Fluid
1005	63°	Fluid
1020	60°	Fluid
1032	57°	Fluid
1045	54°	Fluid
1100	51°	Fluid
1110	49°	Fluid
1121	46°	Fluid
1135	44°	slight movement
1145	42°	no movement

Sample taken from #1 can, put oven overnight for 16 hrs at 65°C / 150°F

#3 sample

Date 8-6-80 Sample No. P.A.G-H16-65°C

By WC. Source Accidental

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
0900	94°	Fluid
0908	85°	Fluid
0916	78°	Fluid
0928	73°	Fluid
0942	69°	Fluid
0951	66°	Fluid
1005	63°	Fluid
1020	60°	Fluid
1032	58°	Fluid
1045	55°	Fluid
1100	52°	Fluid
1110	50°	Fluid
1121	48°	Fluid
1135	45°	slight movement
1145	43°	no movement

Sample taken from #11 can, put in oven overnight for 16 hrs. at 65°C / 150°F

Date 8-1-80 Sample No. Rt-6-54-H3

By W. C. Source Occidental

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
1616	109°	Fluid
1623	92°	Fluid
1633	74°	Fluid
1645	62°	Fluid
1650	58°	no movement

Sample from #1 can, sheared 1 hrs. then heated 3 hrs. at 75°C / 167°F Water Bath temp. at 8°C

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 8-14-80

PREPARED BY W.C.

SYSTEM A-Cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS

NOMINAL % | ACTUAL %

TEMPERATURES

BEFORE 99.9 °F 37.7 °C | AFTER 99.9 °F 37.7 °C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				R.M.6-11/-54-H3 Hr @167°F
2				on 8/11/80
3	3.4	3.3	3.35	
4	4.7	4.5	4.6	
5	6.0	6.0	6.0	
6	8.7	8.7	8.7	
7	11.8	11.7	11.75	
8	15.5	15.5	15.5	
9	20.8	20.7	20.75	
10	27.5	27.4	27.45	
11	40.2	40.1	40.15	
12	54.4	54.3	54.35	
13	72.3	72.1	72.20	
14	97.4		97.4	
15	off-scale		—	

DRY CUPS

BEFORE

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

$\frac{\text{NET SOLID WEIGHT}}{\text{NET SLURRY WEIGHT}}$ _____ × 100 = _____ % WT.

AFTER

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

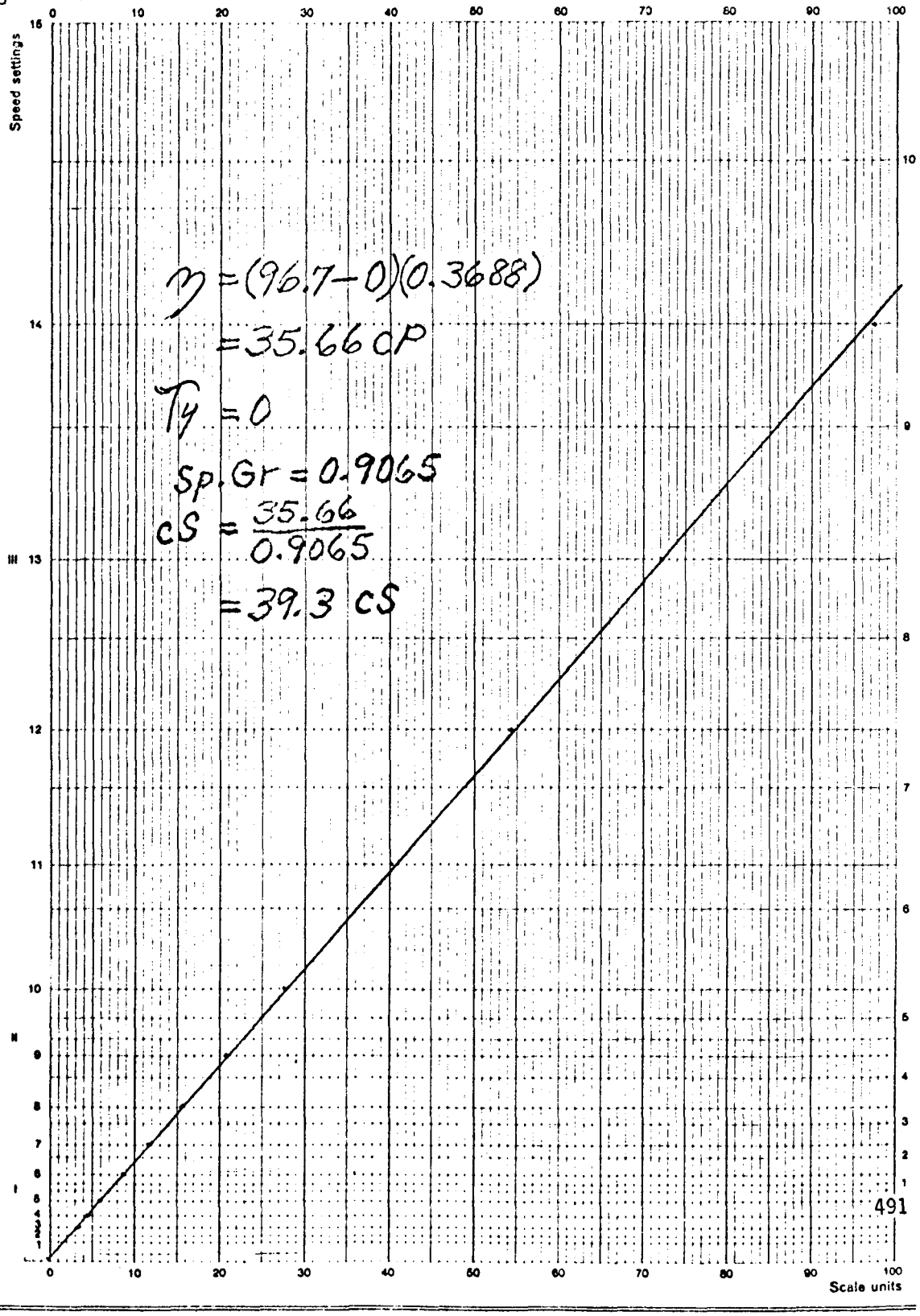
$\frac{\text{NET SOLID WEIGHT}}{\text{NET SLURRY WEIGHT}}$ _____ × 100 = _____ % WT.

SLU 283

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	ID#	NAME	DATE
OCCIDENTAL	A-CUP		HLL	8/14/80
ADDITIVE	COOLING MEDIUM	TEMPERATURE	MATERIAL	
SH.4HR-HT.3HR		99.9 °F	SHALE OIL-RET.#6	



WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 1358 DATE 8-14-80

PREPARED BY W.C.

SYSTEM A-Cup

MATERIAL Shale Cl.

SOURCE Occidental

ADDITIVES —

WEIGHT PER CENT SOLIDS

NOMINAL — % ACTUAL — %

TEMPERATURES

BEFORE 124.1 51.6° ☐F ☐C

AFTER 125.6 52.0° ☐F ☐C

SPEED SET	UP	DOWN	AVERAGE	REMARKS 270 RPM
1				Rot. 6 - #1-54-H3 Hr: @ 167°F
2				on 8/11/80
3				
4				
5				
6	4.6	4.5	4.55	
7	6.2	6.2	6.2	
8	8.3	8.2	8.25	
9	11.1	11.0	11.05	
10	14.8	14.7	14.75	
11	21.7	21.5	21.60	
12	29.5	29.3	29.40	
13	39.4	39.2	39.30	
14	53.4	53.5	53.45	
15	71.9		71.9	

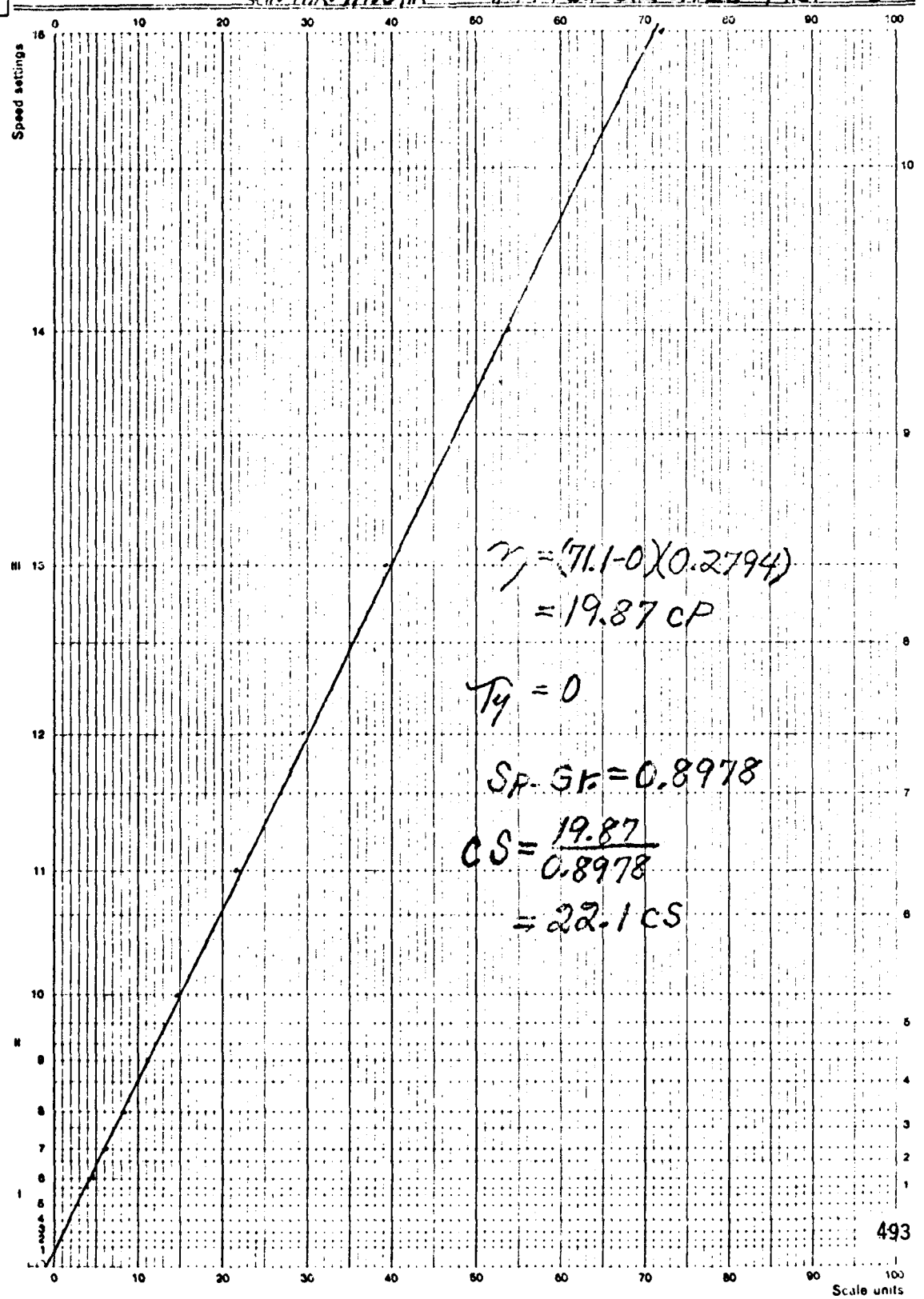
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	_____ GMS	GROSS SLURRY WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SLURRY WEIGHT	_____ GMS	NET SLURRY WEIGHT	_____ GMS
GROSS SOLID WEIGHT	_____ GMS	GROSS SOLID WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SOLID WEIGHT	_____ GMS	NET SOLID WEIGHT	_____ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.	

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL	A-CUP		HLL	8/14/80
SAMPLE	FROM DRILL	MATERIAL		
SH.HLR-HT.3HR	12#-125.6	OIL SHALE - RET. #6		



$\tau_y = (71.1-0)(0.2794)$

$= 19.87$ cP

$\tau_y = 0$

Sp. Gr. $= 0.8978$

$CS = \frac{19.87}{0.8978}$

$= 22.1$ cS

493

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4558 | DATE 8-14-80

PREPARED BY W.C

SYSTEM A-Cup

MATERIAL Whole Oil

SOURCE Occidental

ADDITIVES —

WEIGHT PER CENT SOLIDS — NOMINAL — % | ACTUAL — %

TEMPERATURES — BEFORE 143 to 146 °F °C | AFTER 150 to 165.7 °F °C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				Ref. 6-#1-54-#3 Hrs @ 167°F on 8/1/80
2				
3				Samples for Viscosity Readings
4				Heated 3 hrs at 75°C/167°F
5				8-1-80.
6				
7	3.8	3.7	3.75	
8	5.1	4.9	5.00	
9	6.8	6.7	6.75	
10	9.1	8.9	9.00	
11	13.4	13.2	13.30	
12	18.3	18.2	18.25	
13	24.6	24.5	24.55	
14	33.5	33.4	33.45	
15	45.5		45.50	

DRY CUPS

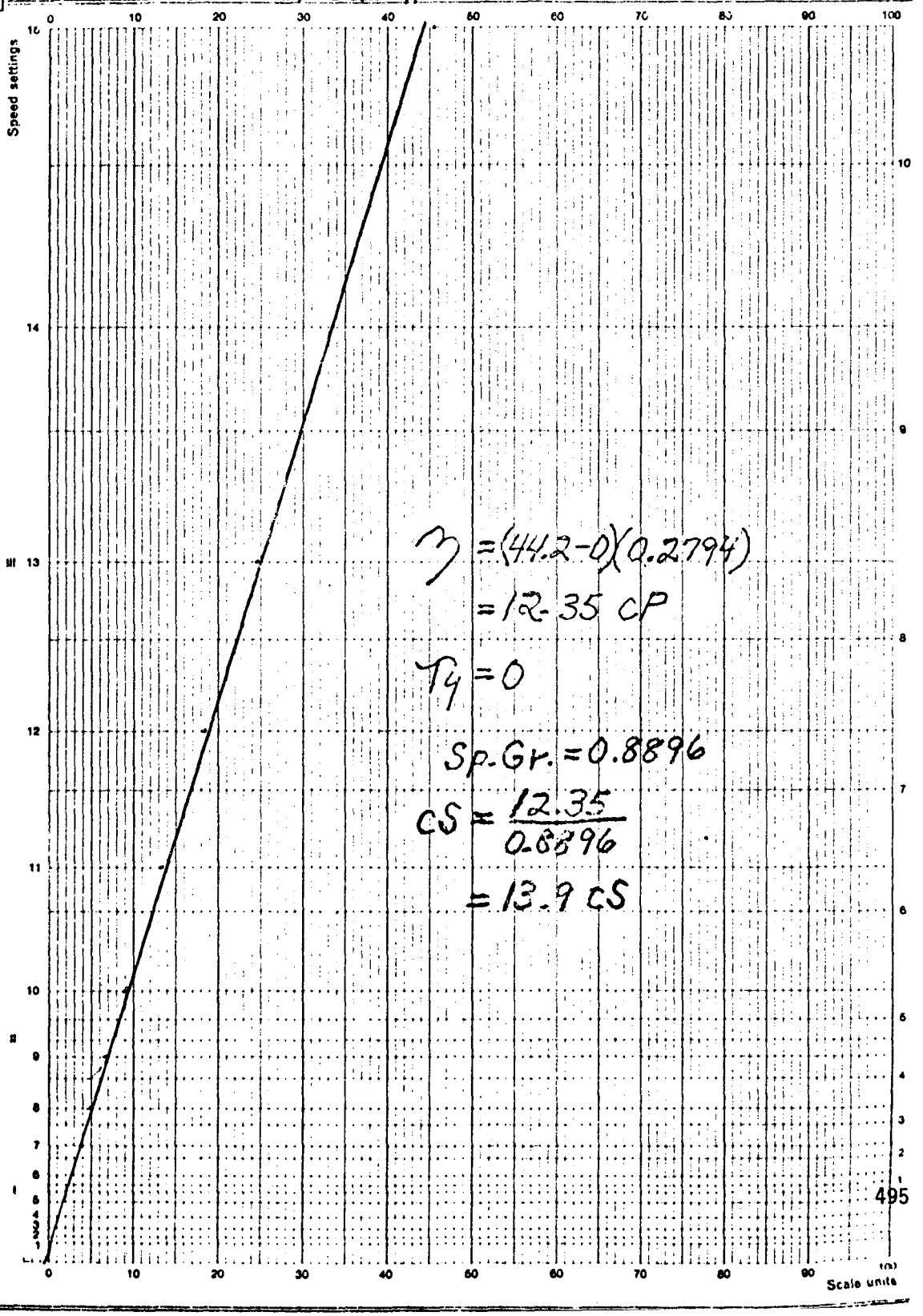
BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	_____ GMS	GROSS SLURRY WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SLURRY WEIGHT	_____ GMS	NET SLURRY WEIGHT	_____ GMS
GROSS SOLID WEIGHT	_____ GMS	GROSS SOLID WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SOLID WEIGHT	_____ GMS	NET SOLID WEIGHT	_____ GMS
494 NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.

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WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

TEST CONDITION	SYSTEM	PH	NAME	DATE
OCCIDENTAL	A-CUP		HLL	8/14/80
ADDITIVE	CONCENTRATION	TEMPERATURE	MATERIAL	
SH.4 HR-HT-3 HR		145°-150°	OIL SHALE - RET. #6	



$$\eta = (44.2-0)(0.2794)$$
$$= 12.35 \text{ cP}$$

$$\tau_y = 0$$

$$\text{Sp. Gr.} = 0.8896$$

$$\text{cS} = \frac{12.35}{0.8896}$$
$$= 13.9 \text{ cS}$$

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 DATE 8-15-80

PREPARED BY W. C.

SYSTEM 6-Cup

MATERIAL Shale Dip

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS

NOMINAL ____ % ACTUAL ____ %

TEMPERATURES

BEFORE 68.2 – 20.1 °F °C

AFTER 68.5 – 20.3 °F °C

SPEED SET	UP	DOWN	AVERAGE 2nd Up	AVERAGE 2nd Down	REMARKS 300 RPM
1	14.0	6.2	7.6	7.0	Ref. 6-1-54-H-5 #1677F
2	15.8	8.0	8.7	2.8	OTN 8/1/30
3	17.1	9.1	10.1	8.8	
4	19.8	10.7	11.7	10.3	
5	22.7	12.8	13.8	12.2	
6	26.7	16.5	17.6	15.7	
7	31.8	20.7	21.9	19.7	
8	36.6	25.9	27.2	24.5	
9	45.2	33.0	34.4	31.3	
10	55.0	41.9	43.3	39.8	
11	65.1	58.5	58.6	52.6	
12	82.2	76.8	75.6	73.2	
13	off scale		95.0		
14					
15					

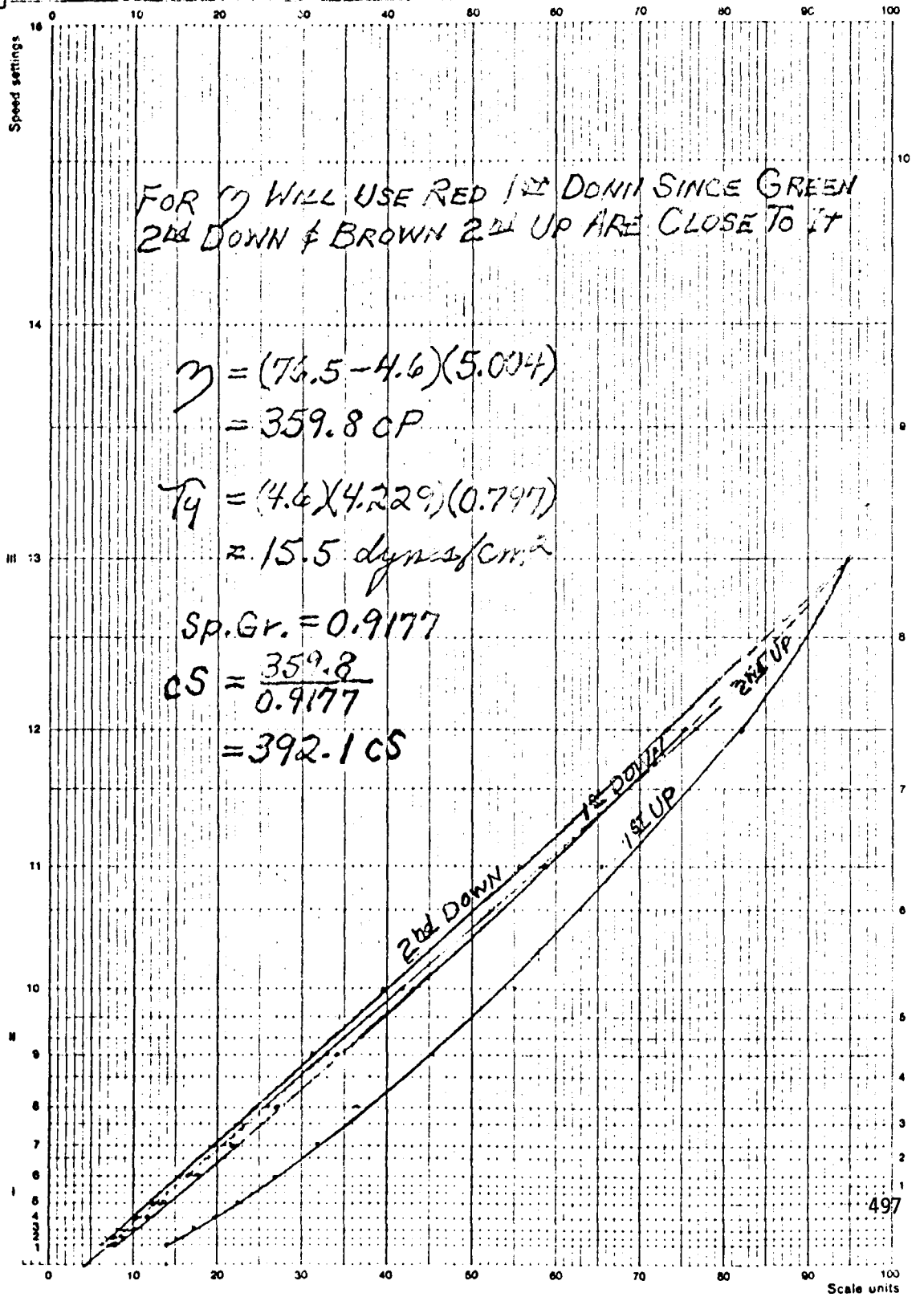
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	____ GMS	GROSS SLURRY WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SLURRY WEIGHT	____ GMS	NET SLURRY WEIGHT	____ GMS
GROSS SOLID WEIGHT	____ GMS	GROSS SOLID WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SOLID WEIGHT	____ GMS	NET SOLID WEIGHT	____ GMS
496			
NET SOLID WEIGHT / NET SLURRY WEIGHT ____ × 100 = ____ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT ____ × 100 = ____ % WT.	

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL B-CUP	HLL	8/15/80
SH.4 HR-HT.318 @ 62.4°	SEALE OIL-RET.#6	



FOR η WILL USE RED 1ST DOWN SINCE GREEN 2ND DOWN & BROWN 2ND UP ARE CLOSE TO IT

$\eta = (78.5 - 4.6)(5.004)$

$= 359.8$ cP

$\tau_y = (4.6)(4.229)(0.797)$

≈ 15.5 dynes/cm²

Sp.Gr. $= 0.9177$

$cS = \frac{359.8}{0.9177}$

$= 392.1$ cS

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 8-15-80

PREPARED BY W. C.

SYSTEM 6-Aug

MATERIAL Black Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS

NOMINAL ____ % | ACTUAL ____ %

TEMPERATURES

BEFORE 74.7 °F 23.7 °C | AFTER 74.7 °F 23.7 °C

SPEED SET	UP	DOWN	~~UP~~	Down	REMARKS
1					Cal. j-#1 54-431 rs @ 167°F on 8/11/80
2					
3	3.3		3.3		
4	4.1	3.7	4.1	3.7	
5	5.1	4.6	5.1	4.6	
6	6.9	6.2	6.7	6.1	
7	8.9	8.1	8.7	7.9	
8	11.3	10.3	10.9	10.1	
9	14.6	13.3	14.0	13.1	
10	18.8	17.2	17.9	17.0	
11	26.5	24.5	25.2	24.2	
12	34.8	32.5	33.2	32.1	
13	44.7	42.4	43.0	41.9	
14	57.9	56.1	56.5	55.5	
15	73.9		73.0		

DRY CUPS

BEFORE

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

498

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ x 100 = _____ % WT.

AFTER

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

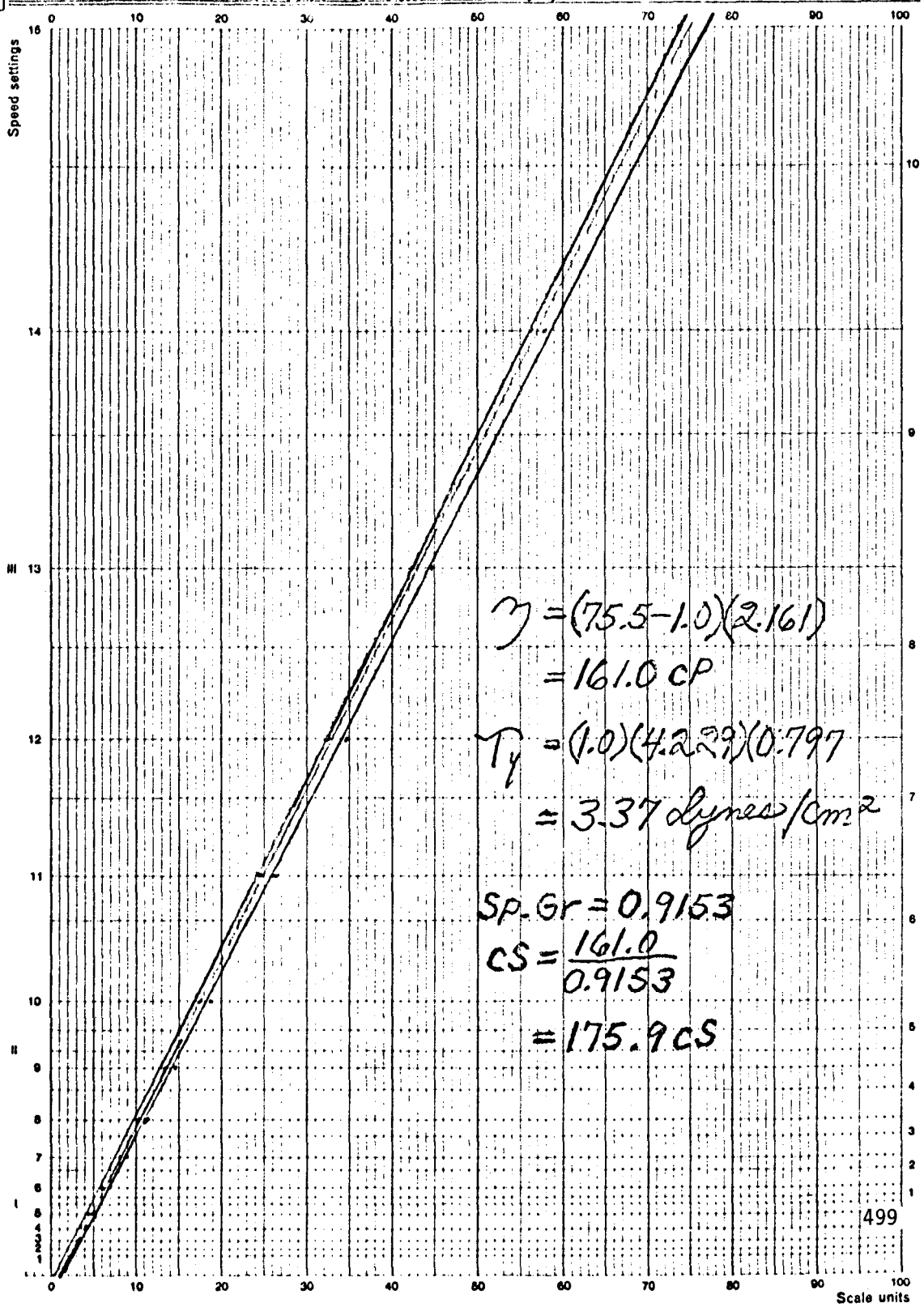
NET SOLID WEIGHT / NET SLURRY WEIGHT _____ x 100 = _____ % WT.

BLU-289

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

PROGRAM NO.	SYSTEM	PH	NAME	DATE
OCCIDENTAL	B-CUP		HLL	8/15/80
SAMPLE	CORE NO.	FORMATION	MATERIAL	
SH.41'K-HT.3HR	77.7		SHALE OIL-RET. #6	



$\eta = (75.5 - 1.0)(2.161)$

$= 161.0$ cP

$\tau_y = (1.0)(4.29)(0.797)$

$\simeq 3.37$ dynes/cm^2

Sp. Gr $= 0.9153$

$cS = \frac{161.0}{0.9153}$

$= 175.9$ cS

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 8-28-80

PREPARED BY W.C.

SYSTEM B-Cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS
NOMINAL ____ % | ACTUAL ____ %

TEMPERATURES
BEFORE 15.5 °F ☐C | AFTER 15.5 °F ☐C

59.9 °F

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1	13.1	12.4		Ref. 6-#1-Oil Received
2	15.3	14.0		
3	17.6	15.7		
4	20.9	18.1		
5	24.5	21.0		Approx. 1 min. intervals
6	31.0	26.4		between readings
7	38.1	32.3		
8	46.1	39.3		
9	56.8	49.0		
10	68.6	61.2		
11	86.8	84.2		
12	—	—		
13				
14				
15				

DRY CUPS

BEFORE

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

$$\frac{\text{NET SOLID WEIGHT}}{\text{NET SLURRY WEIGHT}} _____ \times 100 = _____ \%\ \text{WT.}$$

500

AFTER

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

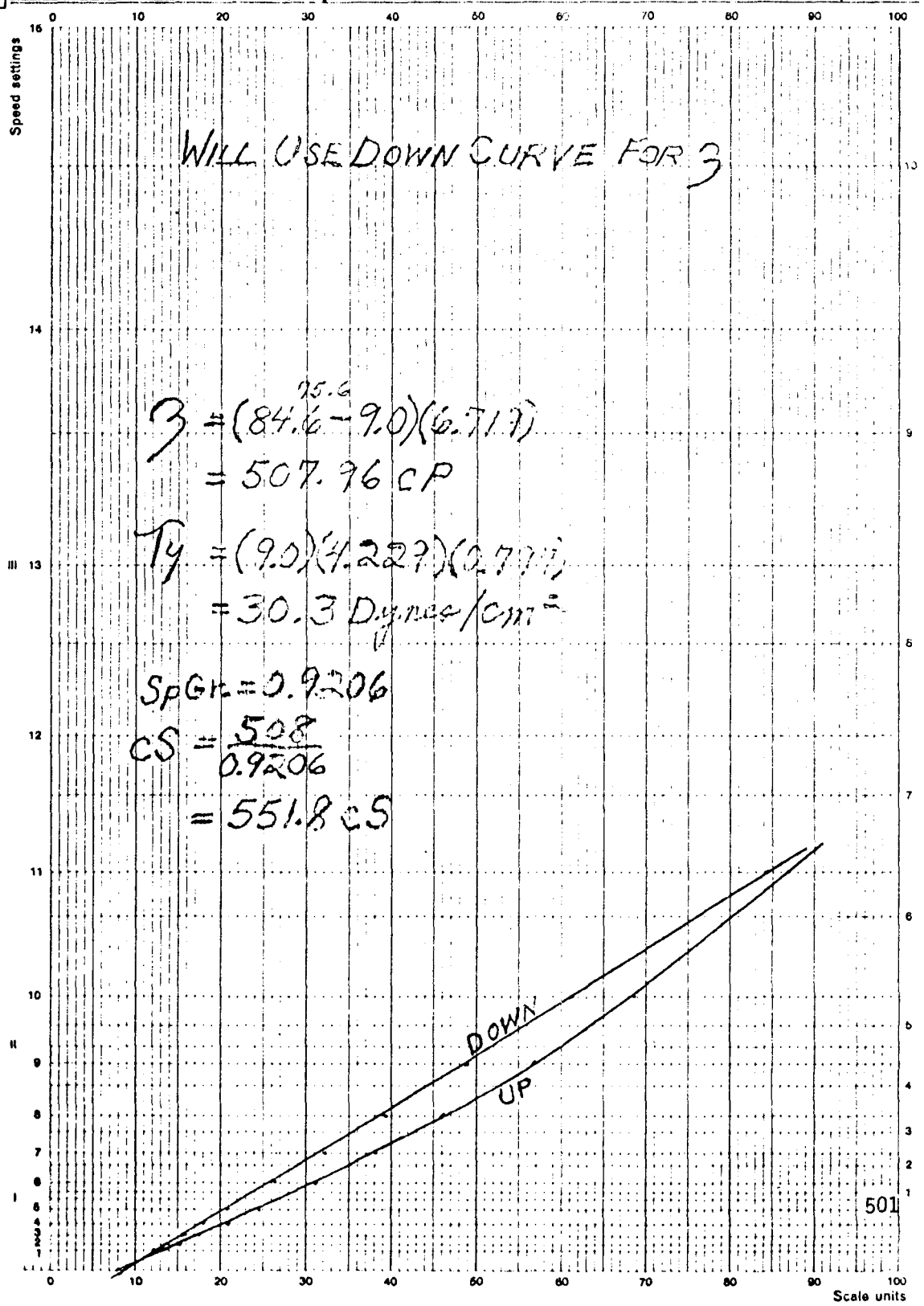
NET SOLID WEIGHT _____ GMS

$$\frac{\text{NET SOLID WEIGHT}}{\text{NET SLURRY WEIGHT}} _____ \times 100 = _____ \%\ \text{WT.}$$

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL	B-CUP		AMBIENT	8/28/80
AS RECEIVED		59.9	SHALE OIL-RETORT #5	



WILL USE DOWN CURVE FOR 3

$$3 = (84.6 - 9.0)(6.717)$$

$$= 507.96 \text{ cp}$$

$$T_y = (9.0)(4.227)(0.707)$$

$$= 30.3 \text{ Dynes/cm}^2$$

$$\text{SpGr} = 0.9206$$

$$CS = \frac{508}{0.9206}$$

$$= 551.8 \text{ cS}$$

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA -- CONTRAVES

JOB NO. 4358 | DATE 8-28-80

PREPARED BY W.C.

SYSTEM B-cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS

NOMINAL ____ % | ACTUAL ____ %

TEMPERATURE BEFORE 66.6 °F 19.2 °C | AFTER 66.4 °F 19.4 °C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1	4.1	4.3		Ret. 6-#1-as Recieved-?
2	5.0	4.9		
3	5.9	5.7		2nd Sample Test
4	7.2	6.7		
5	8.7	8.0		
6	11.5	10.4		1 min. interval between
7	14.6	13.1		readings, up and down
8	18.3	16.3		
9	23.4	20.8		
10	29.7	26.5		
11	41.3	37.3		
12	53.3	49.1		
13	67.3	63.7		
14	85.8	84.6		
15	5 min.			

DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN:	☐AM ☐PM	TIME PLACED IN OVEN:	☐AM ☐PM
GROSS SLURRY WEIGHT	____ GMS	GROSS SLURRY WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SLURRY WEIGHT	____ GMS	NET SLURRY WEIGHT	____ GMS
GROSS SOLID WEIGHT	____ GMS	GROSS SOLID WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SOLID WEIGHT	____ GMS	NET SOLID WEIGHT	____ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT	____ × 100 = ____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	____ × 100 = ____ % WT.

502

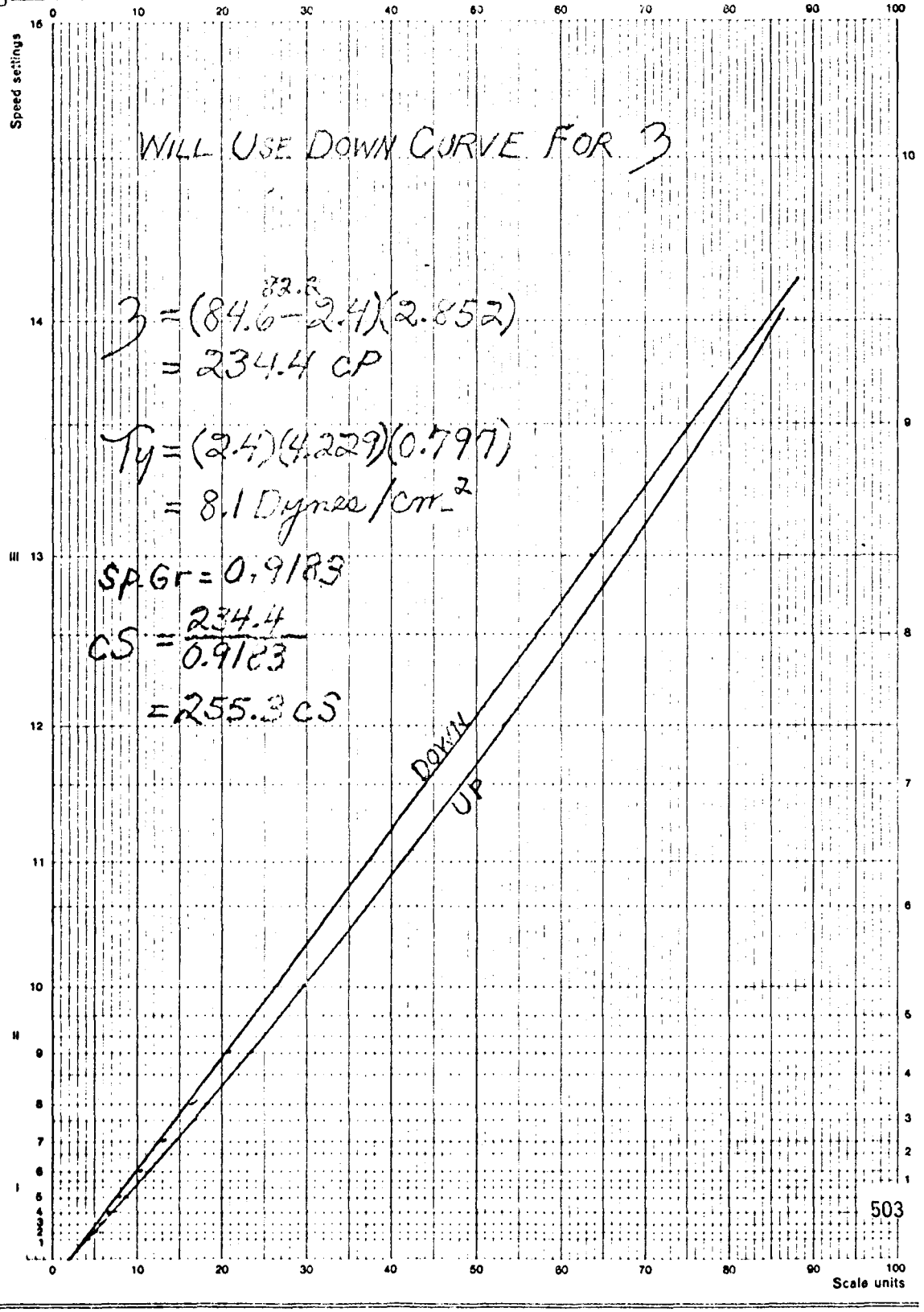
BLU-200

WILLIAMS BROTHERS ENGINEERING COMPANY

2nd SAMPLE TEST

RHEOGRAM

OCCIDENTAL	B-CUP	HLL	8/28/80
AS RECEIVED	82.8	SHALE OIL - RETORT #6	



WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA -- CONTRAVES

JOB NO. 4258 | DATE 8-28-80

PREPARED BY W.C

SYSTEM B-Cup

MATERIAL Blade Oil

SOURCE Occidental

WEIGHT PER CENT SOLIDS — NOMINAL ___ % | ACTUAL ___ %

TEMPERATURE BEFORE 67.3 °F 19.6 °C | AFTER 68.0 °F 20.0 °C

ADDITIVES # ___

66.7°F 19.3°C | 67.1°F 19.5°C

SPEED SET	UP	DOWN	UP	DOWN	REMARKS
1	6.8	3.4	4.2	5.2	8-26-#1-As Received-1
2	7.9	4.1	5.2	5.8	
3	9.3	4.8	6.1	6.5	1st Sample Test
4	11.1	5.8	7.1	7.6	
5	13.1	7.1	8.9	8.8	
6	16.3	9.5	11.8	11.2	
7	20.2	12.1	15.0	13.9	
8	24.6	15.7	18.8	17.3	
9	30.2	19.9	23.9	21.9	
10	36.3	25.5	30.2	27.6	
11	44.4	36.1	42.0	38.4	
12	56.8	47.7	54.6	50.2	
13	70.2	61.9	69.4	64.7	
14	87.4	82.1	88.5	85.1	
15	off-scale				

DRY CUPS

BEFORE

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT ___ GMS

LESS: CUP #___ TARE ___ GMS

NET SLURRY WEIGHT ___ GMS

GROSS SOLID WEIGHT ___ GMS

LESS: CUP #___ TARE ___ GMS

NET SOLID WEIGHT ___ GMS

504

NET SOLID WEIGHT / NET SLURRY WEIGHT ___ × 100 = ___ % WT.

AFTER

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT ___ GMS

LESS: CUP #___ TARE ___ GMS

NET SLURRY WEIGHT ___ GMS

GROSS SOLID WEIGHT ___ GMS

LESS: CUP #___ TARE ___ GMS

NET SOLID WEIGHT ___ GMS

NET SOLID WEIGHT / NET SLURRY WEIGHT ___ × 100 = ___ % WT.

BLU-266

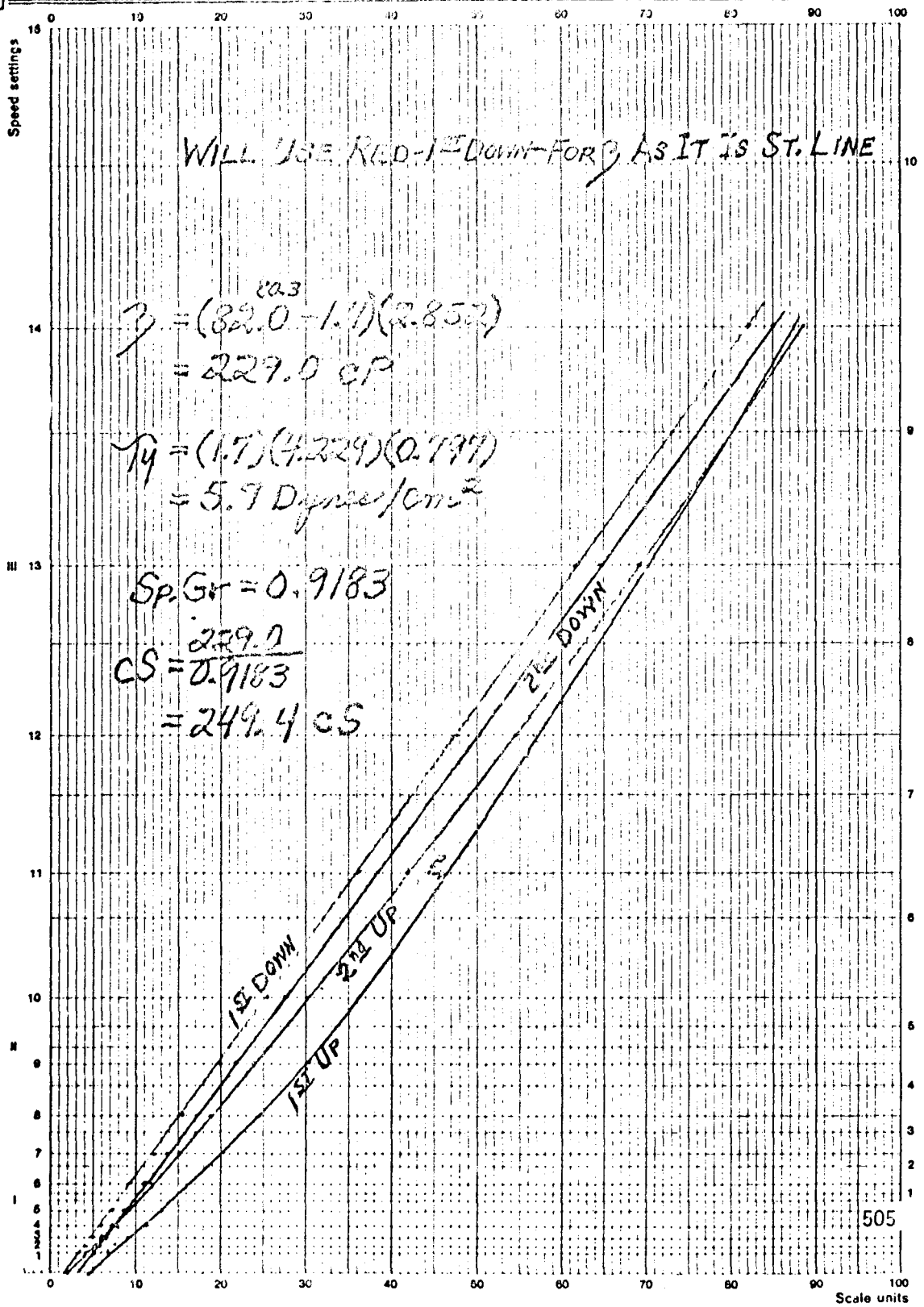
WILLIAMS BROTHERS ENGINEERING COMPANY

1ST SAMPLE TEST

RHEOGRAM

OCCIDENTAL B-CUP | NAME AKK | DATE 8/28/80

AS RECEIVED @ 93° | MATERIAL SHALE OIL - RETORT #6



WILL USE RED-1ST DOWN-FOR 2 AS IT IS ST. LINE

$$\eta = (82.0 - 1.1)(2.852)$$

$$= 229.0 \text{ cp}$$

$$\tau_y = (1.7)(4.229)(0.779)$$

$$= 5.7 \text{ Dynes/cm}^2$$

$$\text{Sp. Gr} = 0.9183$$

$$CS = \frac{229.1}{0.9183}$$

$$= 249.4 \text{ cS}$$

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 458 | DATE 8-29-80

PREPARED BY W.C.

SYSTEM B-Cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS — NOMINAL — % | ACTUAL — %

TEMPERATURES — BEFORE 15.5 °C | AFTER 15.3 °C (59.9°F)

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1	4.1	—		Ref. 6-#1-54-#3 New
2	5.0	3.7		
3	6.0	4.4		
4	7.5	5.5		8-28-80
5	9.2	6.8		Sheared 4 hours at 270 RPMS
6	12.4	9.3		Heated 3 hours at 75°C/167°F
7	15.8	12.1		
8	19.7	15.6		
9	25.0	20.4		
10	31.6	26.5		
11	43.6	38.1		
12	55.2	50.8		
13	69.5	66.6		
14	90.2	88.9		
15	1 min. Interval			

DRY CUPS

BEFORE

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

506

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

AFTER

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

BLU-200

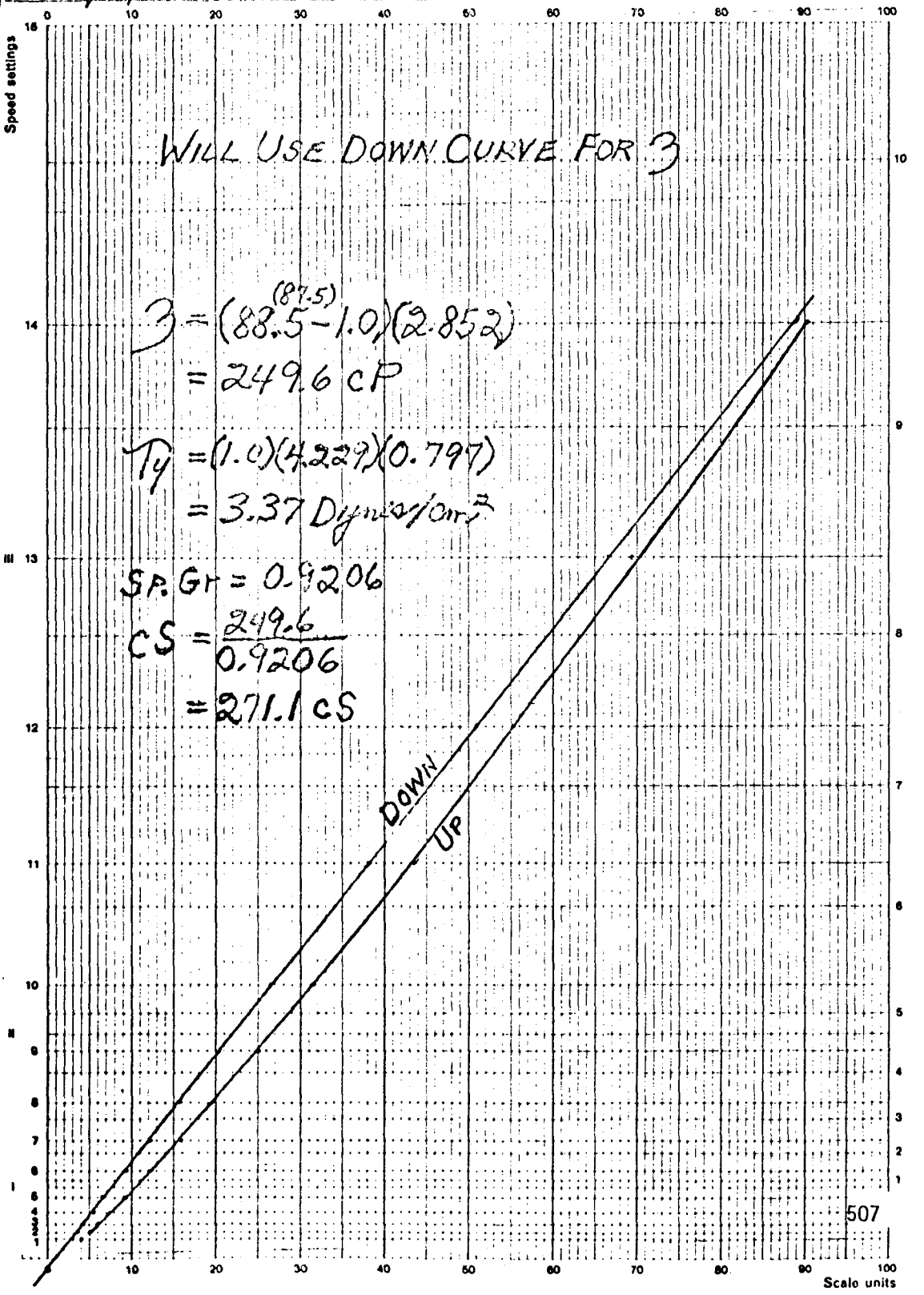
WILLIAMS BROTHERS ENGINEERING COMPANY

NEW

RHEOGRAM

OCCIDENTAL	B-CUP		HLL	8/29/80

8/28/80 WAS SH. 4HR-HT. 3HR @ 59.9°F SHALE OIL-RETORT #6



WILL USE DOWN CURVE FOR 3

$$3 = (88.5^{(87.5)} - 1.0)(2.852)$$
$$= 249.6 \text{ cP}$$

$$Ty = (1.0)(4.229)(0.797)$$
$$= 3.37 \text{ Dynes/cm}^2$$

SP. Gr = 0.9206

$$CS = \frac{249.6}{0.9206}$$
$$= 271.1 \text{ cS}$$

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 735-8 | DATE 8-29-80

PREPARED BY W.C.

SYSTEM B-Cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS

NOMINAL — % | ACTUAL — %

TEMPERATURES

BEFORE 19.5 °F/°C | AFTER 19.5 °F/°C 67.1°F

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				Ret. 6-#1-54-#3 New
2				
3				
4				8-28-80 This sample was
5	1.0	3.6		sheared at 270 RPMs for
6	5.6	5.1		4 hours, then it was heated
7	7.3	6.7		in oven for 3 hours at 25°C/167°F
8	9.5	8.6		
9	12.5	11.4		
10	16.1	14.9		
11	22.8	21.4		
12	30.1	28.6		
13	39.0	37.6		
14	51.1	50.0		
15	66.3			

DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	____ GMS	GROSS SLURRY WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SLURRY WEIGHT	____ GMS	NET SLURRY WEIGHT	____ GMS
GROSS SOLID WEIGHT	____ GMS	GROSS SOLID WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SOLID WEIGHT	____ GMS	NET SOLID WEIGHT	____ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT ____ × 100 = ____ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT ____ × 100 = ____ % WT.	

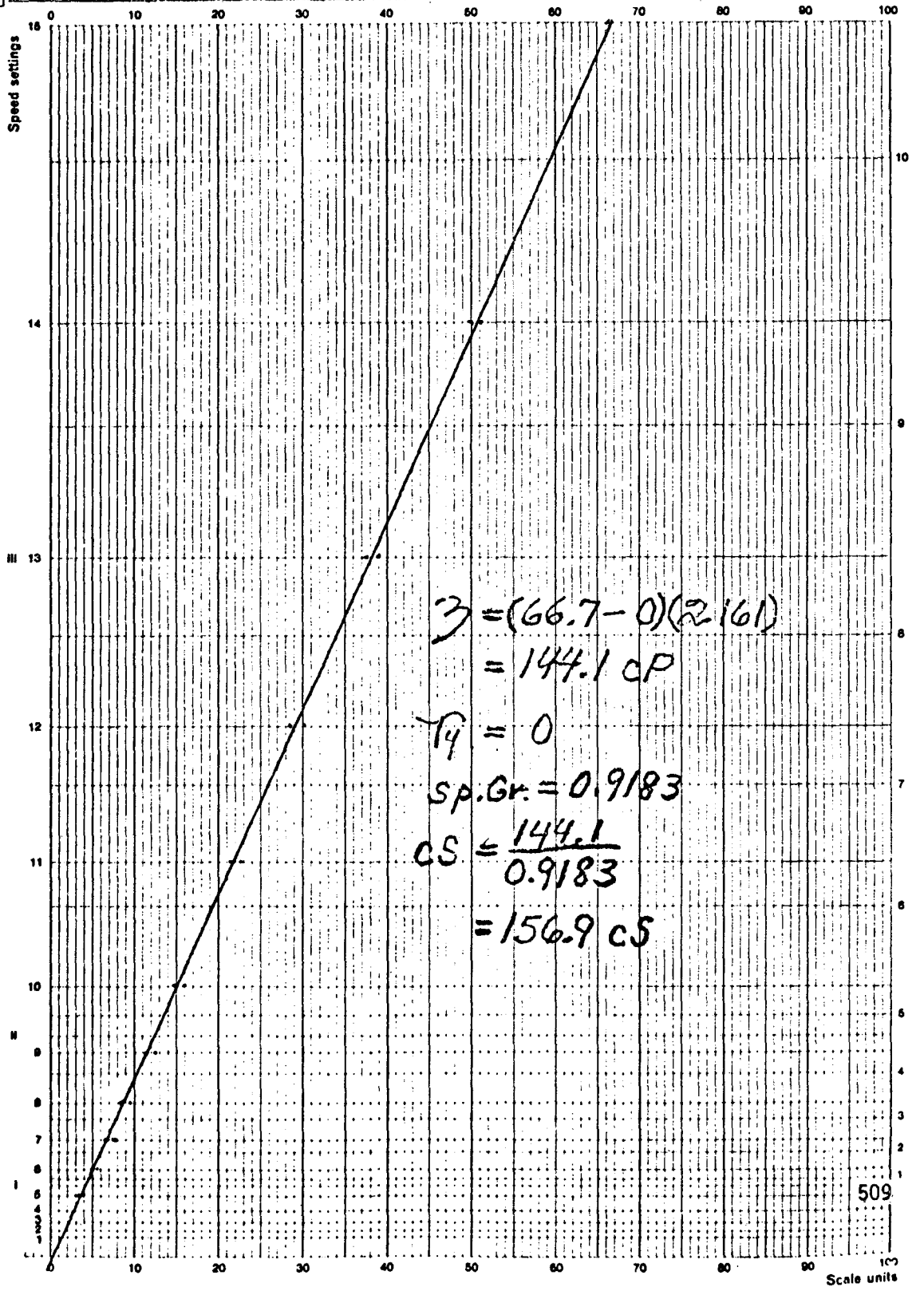
BLU-266

WILLIAMS BROTHERS ENGINEERING COMPANY

NEW

RHEOGRAM 8/28/80 WAS $11.4 HR-HZ 3HR

RHEOGRAM NO.	SYSTEM	PH	NAME	DATE
OCCIDENTAL	B-CUP		JLL	8/29/80
ADDITIVE	CONC. (% WT)	TEMPERATURE	MATERIAL	
	%	67.1 °F	SHALE OIL - RETORT #6	



509

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO.	DATE
4358	8-29-80

PREPARED BY: W.C.

SYSTEM: B-Cup

MATERIAL: Shale Oil

SOURCE: Occidental

ADDITIVES:

WEIGHT PER CENT SOLIDS — NOMINAL — % | ACTUAL — %

TEMPERATURES — BEFORE 15.5 °F °C | AFTER 59.9°F 15.5 °F °C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1	31.6	30.5		Ref. 6-#1-54-#3 Old
2	35.5	33.4		
3	39.1	36.2		
4	44.0	40.3		
5	49.9	45.5		8-1-80 This sample was
6	60.2	55.1		sheared 4 hours at 270 RPMS and
7	70.8	65.8		heated 3 hours at 75°C / 167°F
8	83.0	79.0		
9	98.2	97.8		
10	5 min. interval			1 min. intervals between readings
11				
12				
13				
14				
15				

DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	_____ GMS	GROSS SLURRY WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SLURRY WEIGHT	_____ GMS	NET SLURRY WEIGHT	_____ GMS
GROSS SOLID WEIGHT	_____ GMS	GROSS SOLID WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SOLID WEIGHT	_____ GMS	NET SOLID WEIGHT	_____ GMS
510			
NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.	

SLU-269

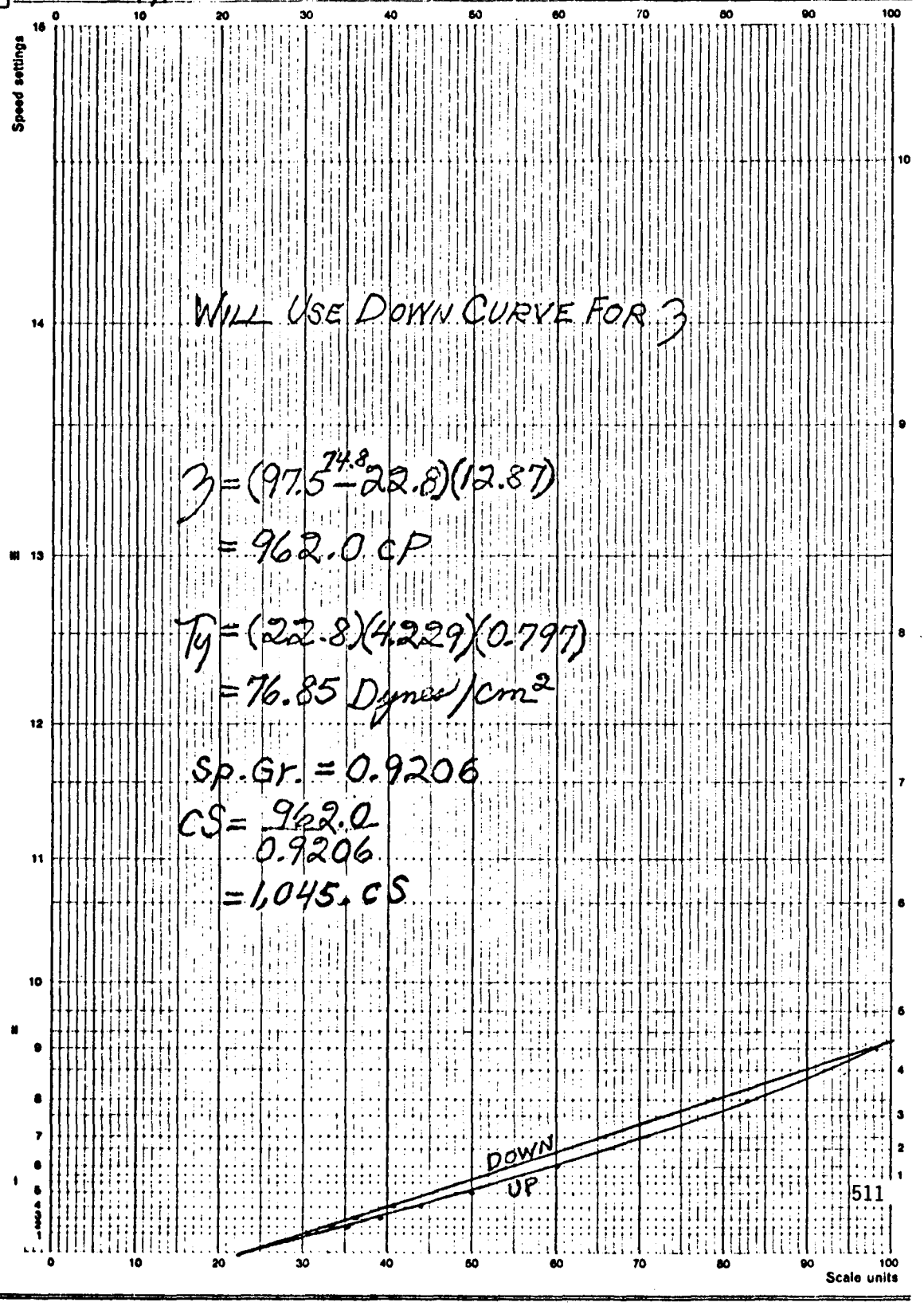
WILLIAMS BROTHERS ENGINEERING COMPANY

OLD

RHEOGRAM

RHEOGRAM NO.	SYSTEM	PH	NAME	DATE
OCCIDENTAL	B-CUP		HLL	8/29/80

8/1/80 Was SH-4Hr-Ht.3Hr | TEMP. 59.9°F | MATERIAL SHALE OIL-RETORT #6



WILL USE DOWN CURVE FOR 3

$$\eta = (97.5 - 22.8)(12.87)$$

$$= 962.0 \text{ cP}$$

$$\tau_y = (22.8)(4.229)(0.797)$$

$$= 76.85 \text{ Dynes/cm}^2$$

Sp. Gr. = 0.9206

$$CS = \frac{962.0}{0.9206}$$

$$= 1,045. \text{ cS}$$

511

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 8-29-80

PREPARED BY W.C.

SYSTEM B-Cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS

NOMINAL ___ % | ACTUAL ___ %

TEMPERATURE

BEFORE 66.2°F / 19.0 °C | AFTER 67.1°F / 19.5 °C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1	24.6	9.1		Ref 6-FF-54-43 old
2	25.5	10.3		
3	26.1	11.6		
4	28.0	13.4		This sample was sheared
5	30.9	15.7		at 270 RPMS for 4 hours, then
6	36.5	19.9		heated at 75°C or 167°F for 3 hrs
7	41.3	24.6		This was done 8-1-80
8	46.8	30.3		
9	53.8	38.1		
10	62.5	47.8		1 min. intervals between readings
11	77.4	66.1		
12	91.4	87.1		
13	↖	↗		
14	5 min.	interval		
15				

DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	___ GMS	GROSS SLURRY WEIGHT	___ GMS
LESS: CUP #___ TARE	___ GMS	LESS: CUP #___ TARE	___ GMS
NET SLURRY WEIGHT	___ GMS	NET SLURRY WEIGHT	___ GMS
GROSS SOLID WEIGHT	___ GMS	GROSS SOLID WEIGHT	___ GMS
LESS: CUP #___ TARE	___ GMS	LESS: CUP #___ TARE	___ GMS
NET SOLID WEIGHT	___ GMS	NET SOLID WEIGHT	___ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT ___ × 100 = ___ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT ___ × 100 = ___ % WT.	

512

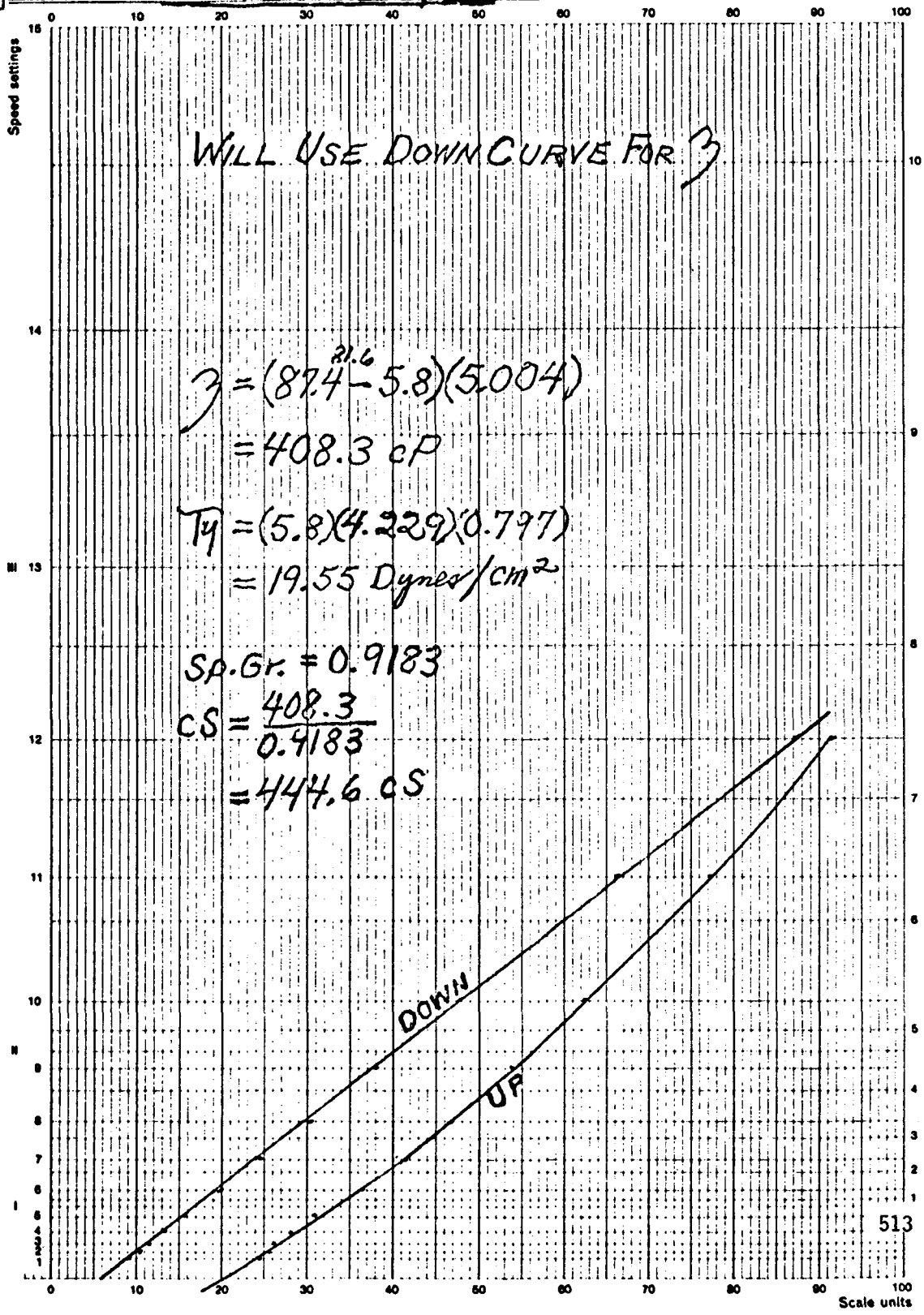
SLU-269

WILLIAMS BROTHERS ENGINEERING COMPANY

OLD

RHEOGRAM

RHEOGRAM NO.	SYSTEM	PH	NAME	DATE
OCCIDENTAL B-CUP			HLL	8/29/80
ADDITIVE	CONC. (%WT)	TEMPERATURE	MATERIAL	
SH. 4 HR. - Ht. 3 He on 8/1/80 - 662-671			SHALE OIL - RETORT #6	



WILL USE DOWN CURVE FOR η

$$\eta = (87.4 - 5.8)(5.004)$$

$$= 408.3 \text{ cP}$$

$$\tau_y = (5.8)(4.229)(0.797)$$

$$= 19.55 \text{ Dynes/cm}^2$$

Sp. Gr. = 0.9183

$$CS = \frac{408.3}{0.4183}$$

$$= 444.6 \text{ cS}$$

APPENDIX NO. 4

OCCIDENTAL SHALE OIL

RETORT NO. 6

POUR POINT AND VISCOSITY

TEST DATA

September, 1980 Series

Data Comparison Tests for

Bench Loop Tests

(Bench Loop Test Data Given in Exhibit 7-3)

Date 9-10-80

By W.C.

Sample No. taken from 55 gal drum

Source Occidental

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
0920	75°	Fluid
0943	68°	Fluid
0953	63°	Fluid
1002	59°	Fluid
1008	56°	Fluid
1022	52°	Fluid
1039	47°	Fluid
1047	45°	Fluid
1102	43°	Fluid
1116	41°	Fluid
1133	39°	Fluid
1142	38°	Fluid
1250	33°	Fluid
1324	31°	Fluid
1334	27°	Fluid
1352	26°	Fluid
1410	24°	Fluid
1438	21°	Slight movement
1600	18°	No movement

BURNETT

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 9-18-80

PREPARED BY W.C.

SYSTEM A - Cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS

NOMINAL ——— % | ACTUAL ——— %

TEMPERATURES °F ☐F ☐C

BEFORE 100.6 °F 38.1 °C | AFTER 99.1 °F 37.3 °C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				
2				
3				
4	4.2		4.2	Sample Taken from 55gal drum
5	5.6	5.6	5.6	
6	8.1		8.1	
7	11.0	11.0	11.0	
8	14.6		14.6	
9	19.5	19.5	19.5	
10	25.7		25.7	
11	37.7	37.7	37.7	
12	50.9		50.9	
13	67.7	67.7	67.7	
14	91.4		91.4	
15	———	———		

DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN:	☐AM ☐PM	TIME PLACED IN OVEN:	☐AM ☐PM
GROSS SLURRY WEIGHT	——— GMS	GROSS SLURRY WEIGHT	——— GMS
LESS: CUP #___ TARE	——— GMS	LESS: CUP #___ TARE	——— GMS
NET SLURRY WEIGHT	——— GMS	NET SLURRY WEIGHT	——— GMS
GROSS SOLID WEIGHT	——— GMS	GROSS SOLID WEIGHT	——— GMS
LESS: CUP #___ TARE	——— GMS	LESS: CUP #___ TARE	——— GMS
NET SOLID WEIGHT	——— GMS	NET SOLID WEIGHT	——— GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT ——— × 100 = ——— % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT ——— × 100 = ——— % WT.	

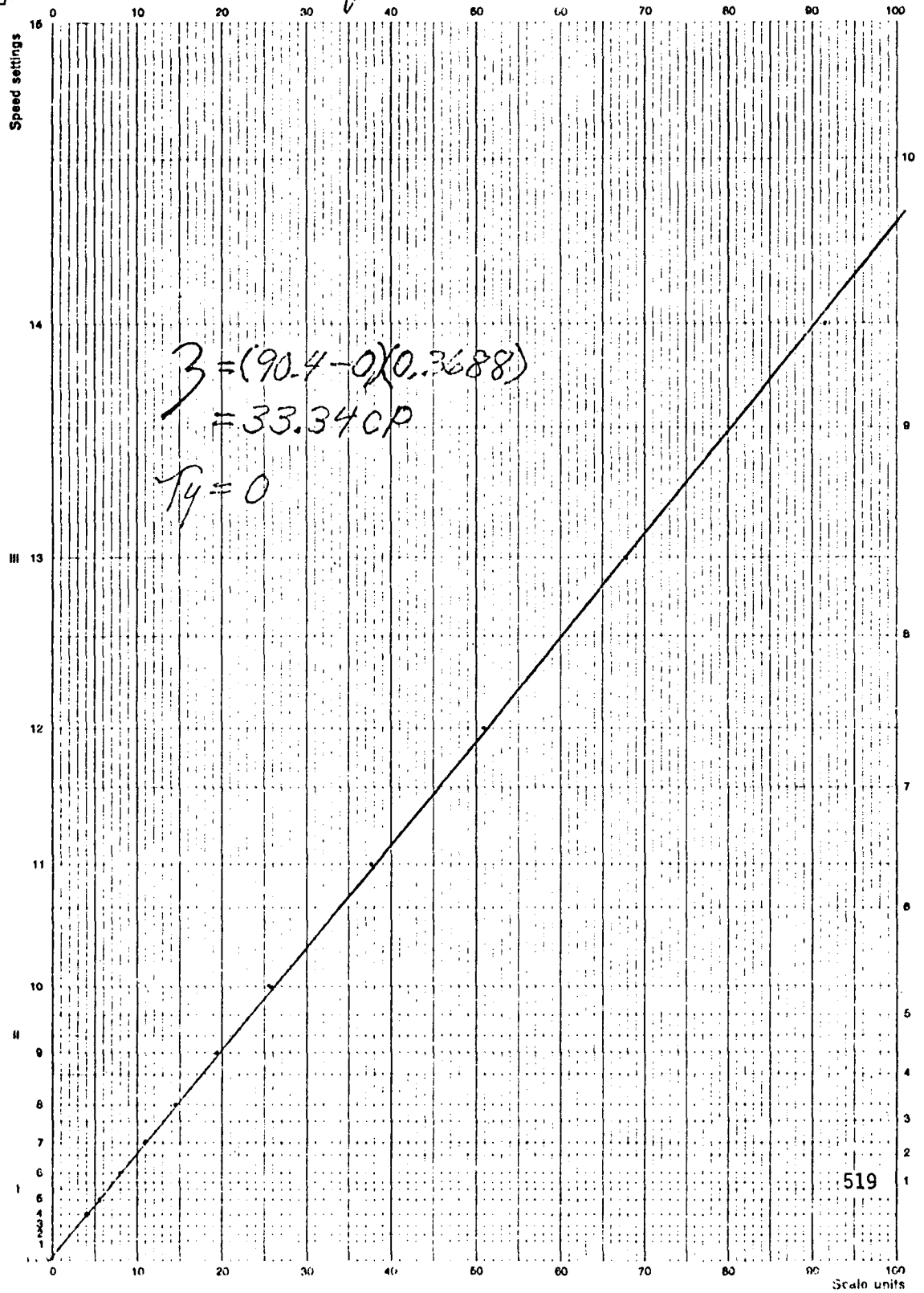
BLU-200

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL	A-CUP		HLL	9/18/80

From 55 gal Drum 103.6-79.1 °F SHALE OIL-RETORT #6



$$\beta = (90.4 - 0)(0.3688)$$
$$= 33.34 \text{ cp}$$
$$\tau_y = 0$$

BURNETT

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 9 18 80

PREPARED BY W. C.

SYSTEM A-Mud

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS

NOMINAL — % | ACTUAL — %

TEMPERATURE BEFORE 77 °F ☐F ☐C | AFTER 75.6 °F ☐F ☐C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1	6.8	6.0		
2	8.7	7.8		
3	11.2	9.9		
4	14.5	12.9		Sample taken from 55 gal. drum
5	18.4	16.5		
6	25.5	23.2		
7	33.1	30.8		
8	42.2	40.1		
9	55.1	53.1		
10	70.7	69.6		
11	off-scale			
12				
13				
14				
15				

DRY CUPS

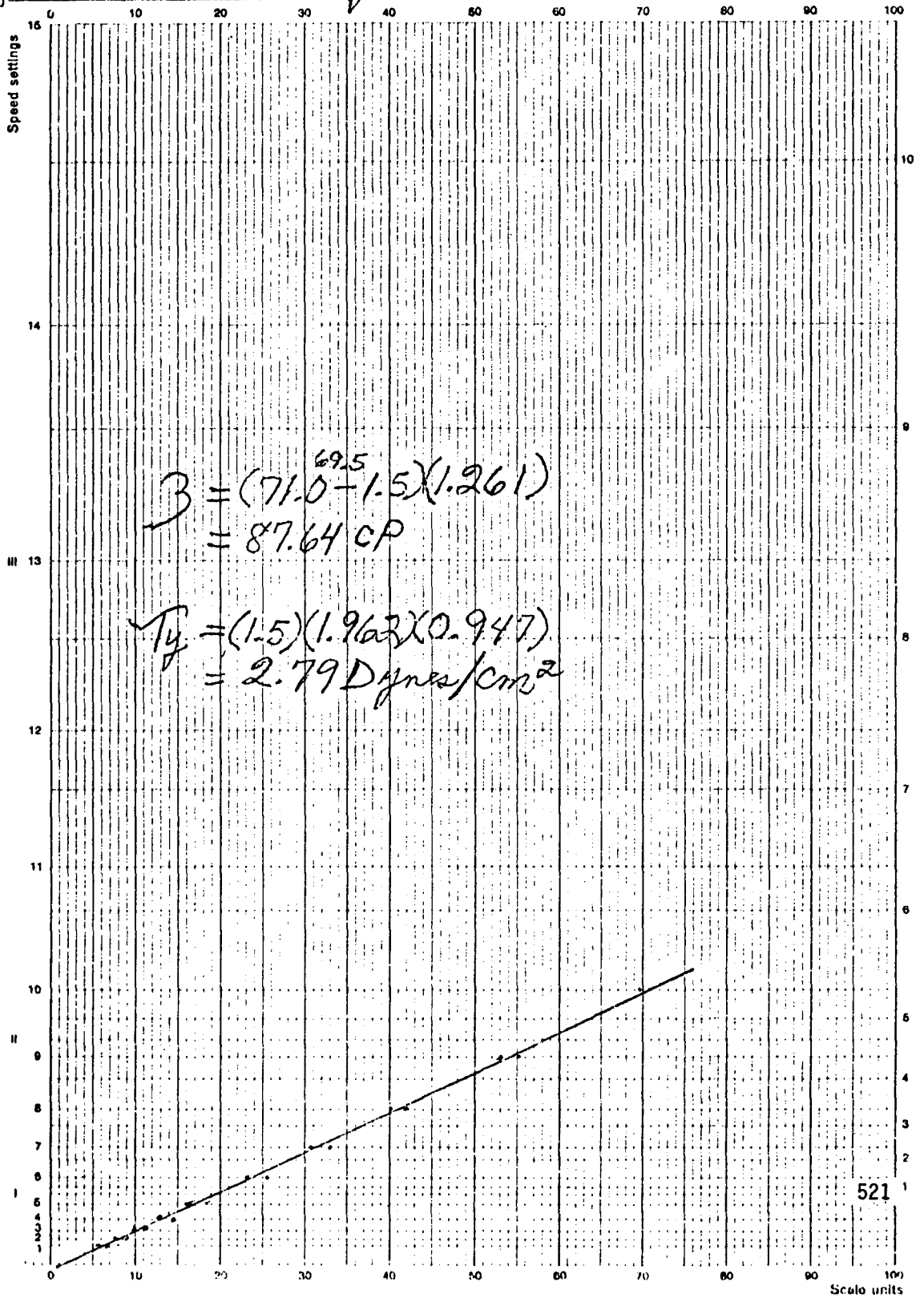
BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	_____ GMS	GROSS SLURRY WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SLURRY WEIGHT	_____ GMS	NET SLURRY WEIGHT	_____ GMS
GROSS SOLID WEIGHT	_____ GMS	GROSS SOLID WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SOLID WEIGHT	_____ GMS	NET SOLID WEIGHT	_____ GMS
520 NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.

SLU-269

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL	A-CUP		HLL	9/18/80
FROM 55 gal Drum	75.4 °F	SHALE OIL - RETORT #6		



$$B = (71.0 - 1.5)(1.261)$$
$$= 87.64 \text{ cP}$$

$$\tau_y = (1.5)(1.962)(0.947)$$
$$= 2.79 \text{ Dynes/cm}^2$$

BURNETT

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 9-18-80

PREPARED BY W.C.

SYSTEM B-Aug

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS
NOMINAL ____ % | ACTUAL ____ %

TEMPERATURES
BEFORE 54.1 °F ☐F ☐C | AFTER 75.4 °F ☐F ☐C
53.4 / 71.1

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				
2				
3				
4				Samples taken from 55 gal drum
5	3.4			
6	4.5	3.6		
7	5.8	4.7		
8	7.4	6.2		
9	9.5	8.1		
10	12.0	10.3		
11	16.8	15.1		
12	21.9	20.2		
13	28.0	26.5		
14	36.5	35.5		
15	47.2			

DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	____ GMS	GROSS SLURRY WEIGHT	____ GMS
LESS: CUP #____ TARE	____ GMS	LESS: CUP #____ TARE	____ GMS
NET SLURRY WEIGHT	____ GMS	NET SLURRY WEIGHT	____ GMS
GROSS SOLID WEIGHT	____ GMS	GROSS SOLID WEIGHT	____ GMS
LESS: CUP #____ TARE	____ GMS	LESS: CUP #____ TARE	____ GMS
NET SOLID WEIGHT	____ GMS	NET SOLID WEIGHT	____ GMS
522 NET SOLID WEIGHT / NET SLURRY WEIGHT ____ × 100 = ____ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT ____ × 100 = ____ % WT.	

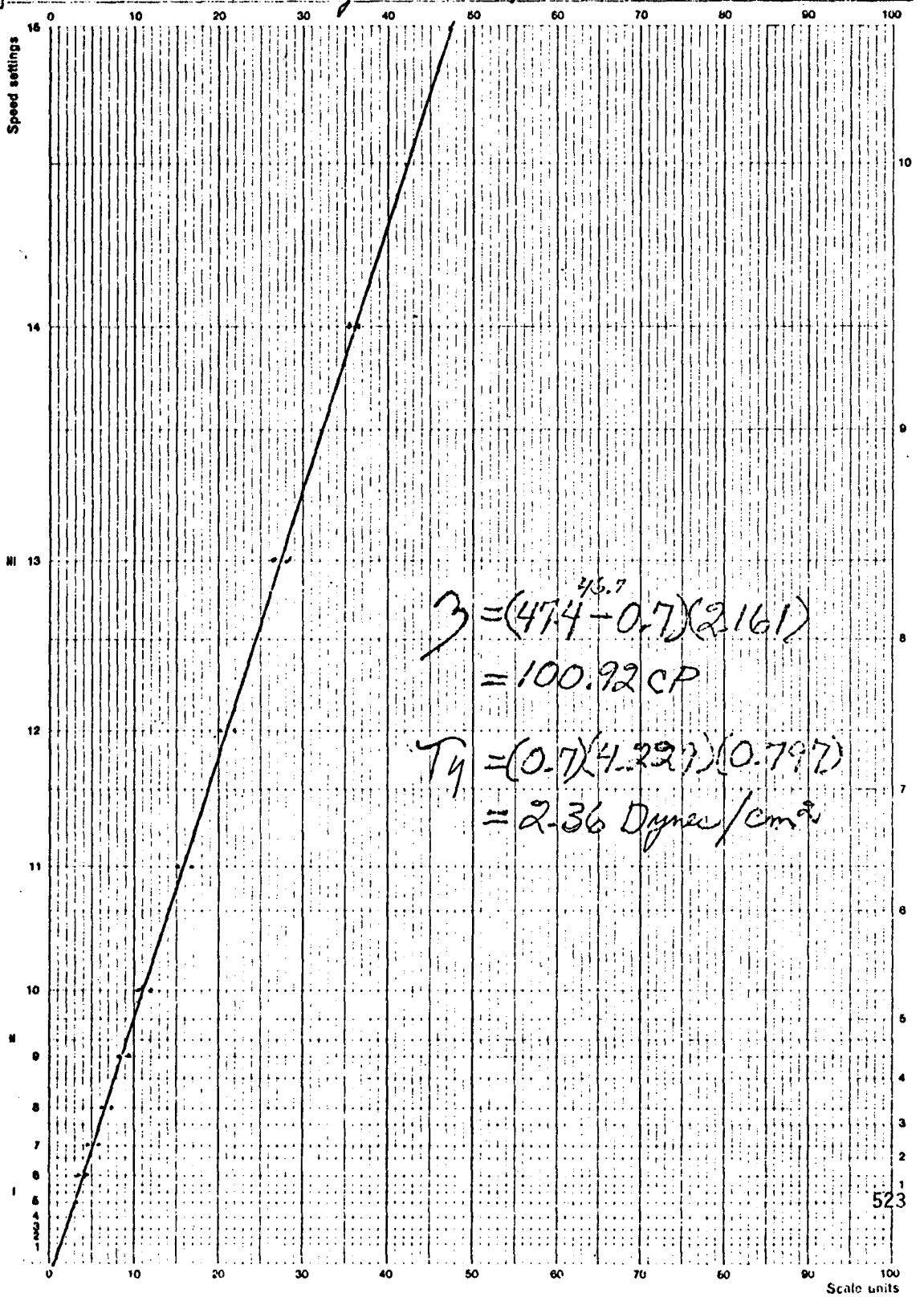
SLU-269

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL	B-CUP		HLL	9/18/80
		MATERIAL		

From 55 gal Drum 74-75 SHALE OIL -- RETORT #6



$$\eta = (47.4 - 0.7)(2.161)$$
$$= 100.92 \text{ cP}$$

$$\tau_y = (0.7)(4.29)(0.797)$$
$$= 2.36 \text{ Dynes/cm}^2$$

DUKNELL

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 9-18-80

PREPARED BY W.C.

SYSTEM A-Gel

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES ———

WEIGHT PER CENT SOLIDS

NOMINAL ——— % | ACTUAL ——— %

TEMPERATURE

BEFORE 122 °F ☐F 50 °C ☐C | AFTER 120.2 °F ☐F 49 °C ☐C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				
2				
3				
4				
5				Sample taken from 55 gal drum
6	4.7	4.8	4.75	
7	6.5	6.5	6.5	
8	8.5	8.6	8.55	
9	11.5	11.6	11.55	
10	15.3	15.3	15.3	
11	22.5	22.5	22.5	
12	30.6	30.7	30.65	
13	40.9	41.0	40.95	
14	55.5	55.5	55.5	
15	74.7		74.7	

DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	——— GMS	GROSS SLURRY WEIGHT	——— GMS
LESS: CUP #___ TARE	——— GMS	LESS: CUP #___ TARE	——— GMS
NET SLURRY WEIGHT	——— GMS	NET SLURRY WEIGHT	——— GMS
GROSS SOLID WEIGHT	——— GMS	GROSS SOLID WEIGHT	——— GMS
LESS: CUP #___ TARE	——— GMS	LESS: CUP #___ TARE	——— GMS
NET SOLID WEIGHT	——— GMS	NET SOLID WEIGHT	——— GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT	——— × 100 = ——— % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	——— × 100 = ——— % WT.

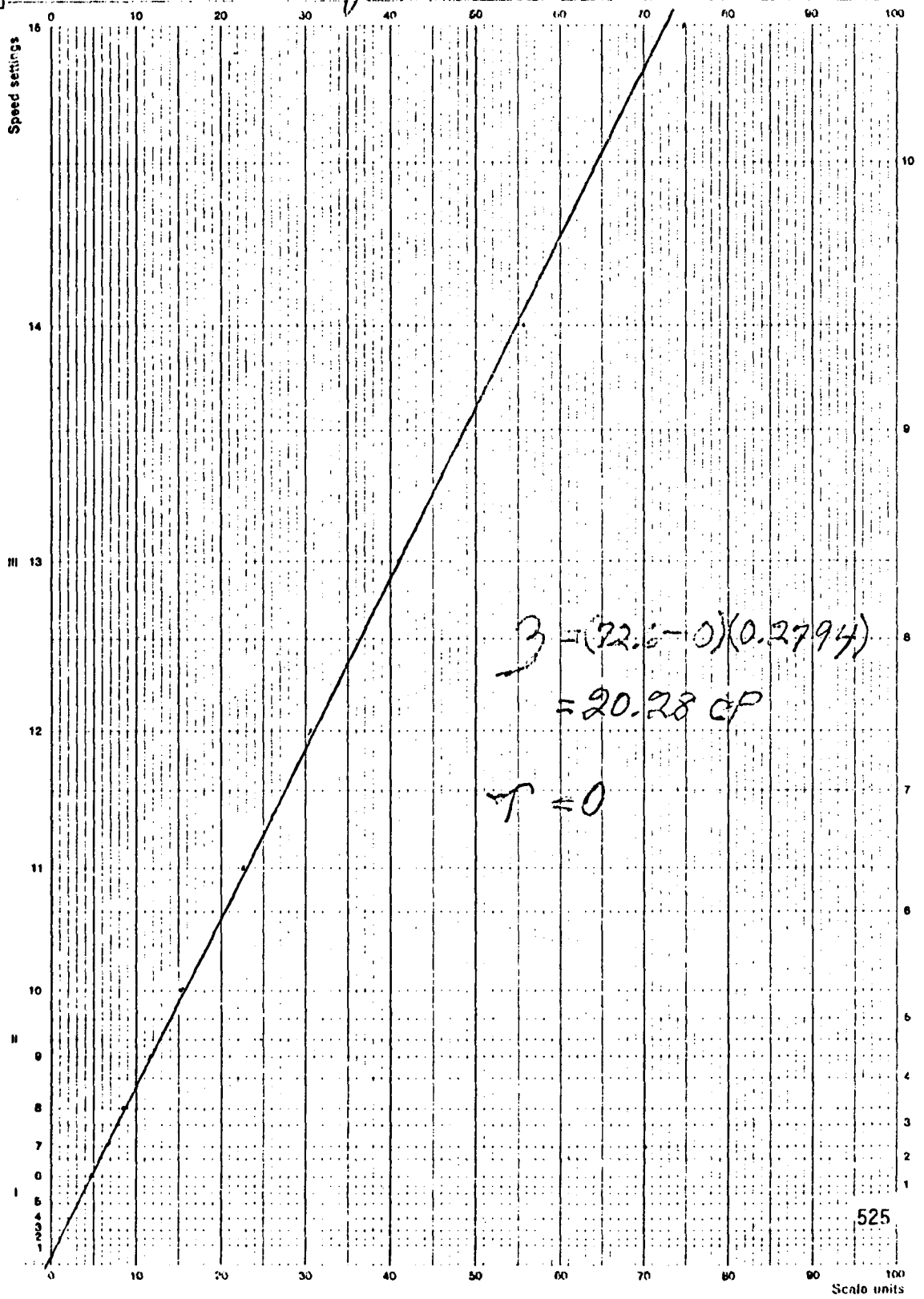
524

SLO-269

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

Accident - A-Cup		HLL	9/18/80
From 55 gal Drum 122-120 SHALE OIL - RETORT #6			



$$\tau = (22.6 - 0)(0.2794)$$

$$= 20.28 \text{ dP}$$

$$\tau = 0$$

BURNETT

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 9-18-80

PREPARED BY W.C.

SYSTEM B-Cup

MATERIAL Shale Oil

SOURCE Occidental

ADDITIVES

WEIGHT PER CENT SOLIDS

NOMINAL — % | ACTUAL — %

TEMPERATURES

BEFORE 59.7°F 152 °C | AFTER 59.2°F 15.1 °C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1	8.4	7.3		
2	9.5	8.2		
3	10.6	9.3		
4	12.3	10.9		Sample taken from 55 gal. drum
5	14.5	13.0		
6	18.5	16.8		
7	23.2	21.2		
8	28.8	26.5		
9	36.7	34.1		
10	46.3	43.7		
11	64.4	61.6		
12	83.6	81.8		
13	—	—		
14				
15				

DRY CUPS

BEFORE

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

526

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

AFTER

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

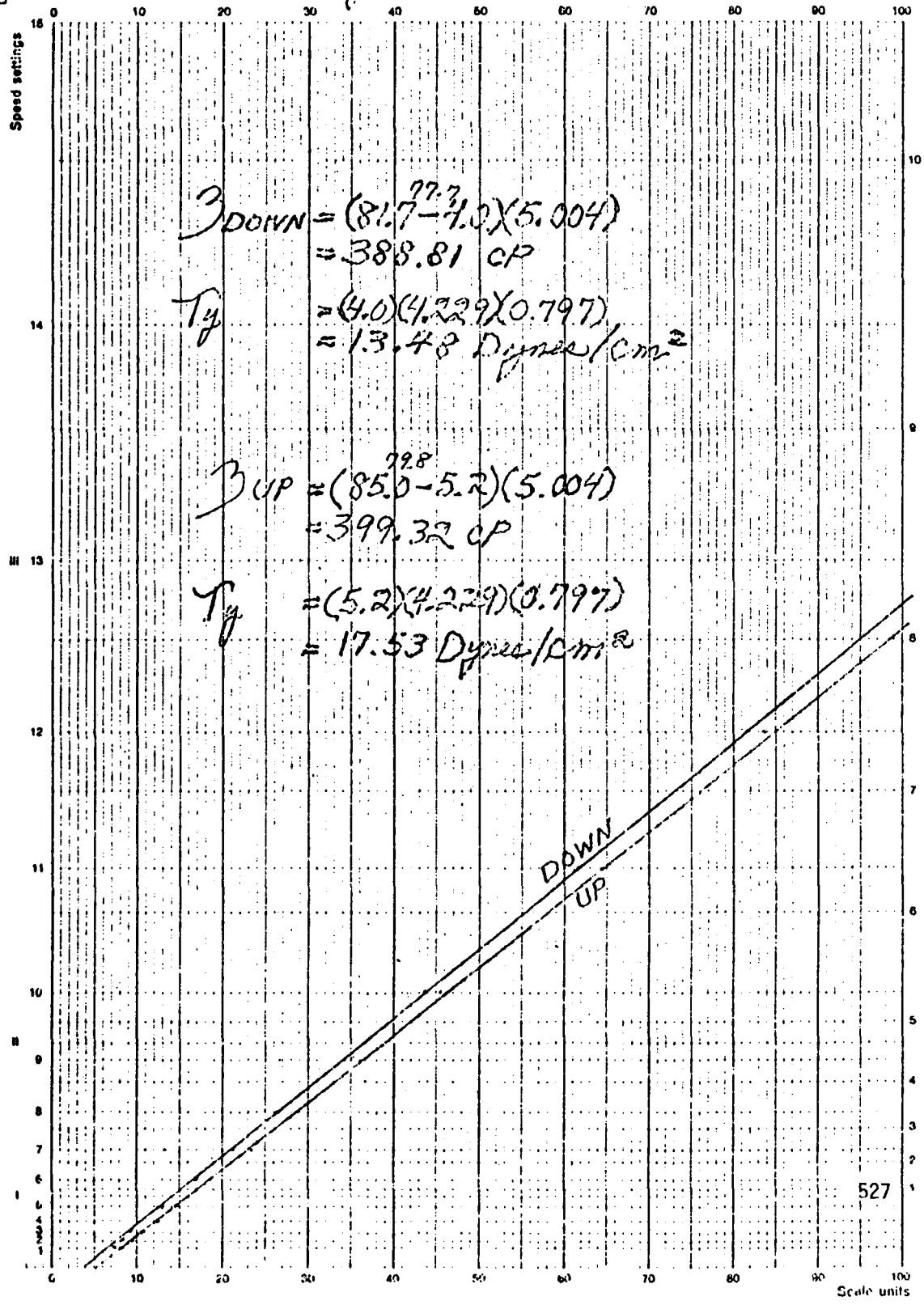
SLU 260

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL | R-CUP | | HLL | 9/18/80

From 55 to Down | 59.3 | SHALE OIL - RETORT #6



$$\tau_{DOWN} = (81.7 - 4.0)(5.004)$$
$$= 388.81 \text{ cp}$$

$$\tau_y = (4.0)(4.229)(0.797)$$
$$= 13.48 \text{ Dynes/cm}^2$$

$$\tau_{UP} = (85.0 - 5.2)(5.004)$$
$$= 399.32 \text{ cp}$$

$$\tau_y = (5.2)(4.229)(0.797)$$
$$= 17.53 \text{ Dynes/cm}^2$$

APPENDIX NO. 5

OCCIDENTAL SHALE OIL

RETORT NO. 6

POUR POINT AND VISCOSITY

TEST DATA

November, 1980 Series

Additive Comparison Tests

WILLIAMS BROTHERS ENGINEERING COMPANY

INTER-OFFICE CORRESPONDENCE

DATE: January 15, 1981

SUBJECT: Log of Occidental Shale Oil Laboratory Tests

TO: File #4358

FROM: Wayne Crow

COPIES: J. Tennant
R. Burnett
H. Lawler

On November 13, 1980, a sample of Occidental's shale oil was removed from the 55-gallon drum to test Nalco Chemical's pour point depressant #5351. Their recommended procedure was to dissolve 0.05 grams in 2 ml of toluene and then mix it with 100 ml of oil heated to 130°-140°F. This was done and the mixture allowed to cool to room temperature. Part of the sample was put in the P.P. tester and part in the viscometer's A cup and viscosities were run at 150°F, 130°F, 110°F and 90°F all on the same day. Time ran out before viscosities at lower temperatures could be run. The pour point (no flow) was 55°F. The viscosity sample was put in a beaker and covered with plastic and sealed with a rubber band. On November 17, 1980, the temperature in the lab was 57°F because of heating system problems. A sample of undoctored oil from the drum was thick but flowable. The sample with the Nalco additive was not flowable and appeared to have a crusted layer on top. It was heated to 75°F and put in the viscometer B cup. The viscometer dial readings were irratic and up readings did not match down readings. An effort to run a viscosity at 65°F was unsuccessful.

November 18, 1980 - a sample of the covered oil-Nalco mixture had five API gravities run on it at 148.1°F, 130.1°F, 109.6°F, 91.4°F and 76.1°F.

Ran pour points on a drum sample of Occidental shale oil on November 26, 1980 to again test Nalco's pour point depressant #5351. Sample was divided into four parts (A, B, C & D). Samples were at 80°F at beginning of tests. Sample A was the standard - no additive or toluene added. Sample B had 0.05 gm of Nalco #5351 added to it. Sample C had 0.05 gm of #5351 and 2 ml of toluene. Sample D had only 2 ml of toluene added to it. All four samples were then heated to 130°F to get good mixing and then allowed to cool. Sample A had a no-flow (was rigid) temperature of 67°F. Sample B had no flow at 33°F. Sample C had no flow at 34°F and Sample D had no flow at 64°F.

December 10, 1980 - Another sample of oil and Nalco #5351 (no toluene) was made up as before to run the P.P. and viscosities at five temperatures (requested in 12/9/80 memo from H.L. Lawler). The purpose of this was to get a new set of data on fresh samples; then let the same samples set two weeks in their respective test containers, and then rerun the same tests. This should give an indication of how stable the Nalco #5351 P.P. depressant is. Due to shortage of time, the sample (400 ml) had to set overnight in a covered beaker.

WILLIAMS
BROTHERS
ENGINEERING
COMPANY

December 11, 1980 - Viscosities (in A cup) were run starting at 150°F and on down to 90°F. The P.P. (no flow) was 25°F. After the 90° viscosity was taken the sample was put into the B cup to try and get viscosities at lower temperatures. At the next lower temperature (about 70°F) the viscometer readings were so irratic that the attempted viscosity was not finished. The samples were kept in their test containers but appeared to be two different samples. The P.P. sample, sealed by its cork and thermometer was very fluid. The viscosity sample, sealed in its A cup with a plastic cover and rubber band, appeared to be crusted over and was very thick.

1358

Date 11-26-80 Sample No. A. Standard

By W.C. Source Oil

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
1010	73°	Fluid
1020	71°	Slight movement
1033	67°	No movement

Sample A. 100ml of Shell oil with no additive. Treated same as samples B.C.D. Heated to 130°F

Date 11-26-80

By W.C.

Sample No. 0. 2cc Toluene/100ml. Shale Oil 80°F

Source Oil

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
1010	73°	Fluid
1020	69°	Slight movement
1033	64°	no movement

Sample 0. 2cc s of Toluene in 100 ml. of Shale oil at 80.°F

Heated to 130°F

4358.

Date 11-26-80

By M.C.

Sample No. C-05gm-5351/2cc Toluene 100 ml Shale Oil 80°F

Source Ogm

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
1010	73°	Fluid
1020	69°	Fluid
1033	64°	Fluid
1041	61°	Fluid
1048	58°	Fluid
1055	55°	Fluid
1100	54°	Fluid
1110	52°	Fluid
1122	49°	Fluid
1133	48°	Fluid
1140	47°	Fluid
1500	45°	Fluid
1525	43°	Fluid
1545	41°	Fluid
1605	38°	Fluid
1115	36°	Slight movement
1630	35°	Slight movement
1647	34°	no movement

535

Sample C. 0.05gm of 5351 Malco plus 2cc.s of Toluene in 100ml of shale oil at 80°F. Heated to 130°F to add 5351 Malco and mix

Date 11-26-80 Sample No. B.0.05gm 5351 / 100ml. Shale Oil 80°F

By W.C. Source Ogg

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
1010	74°	Fluid
1020	70°	Fluid
1033	66°	Fluid
1041	63°	Fluid
1048	60°	Fluid
1055	57°	Fluid
1100	56°	Fluid
1110	54°	Fluid
1122	52°	Fluid
1133	50°	Fluid
1140	49°	Fluid
1500	47°	Fluid
1525	46°	Fluid
1545	44°	Fluid
1605	40°	Fluid
1615	39°	Fluid
1630	38°	Fluid
1647	37°	Fluid
1706	35°	Slight movement
1717	33°	no movement

Sample B. 0.05gm of 5351 Oako in 100ml. of Shale oil at 80°F, Heated to 150°F for mixing

Date 11-12-80 Sample No. 55 gal. Drum

By W.C. Source Ogu

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
0950	64°	Fluid
1000	62°	Fluid
1010	59°	Fluid
1020	56°	Fluid
1034	51°	Fluid
1048	48°	Fluid
1054	47°	Fluid
1100	46°	Fluid
1114	45°	Slight movement
1121	44°	" "
1130	42°	no movement

Date 11-12-80 Sample No. Gal. Cans #4

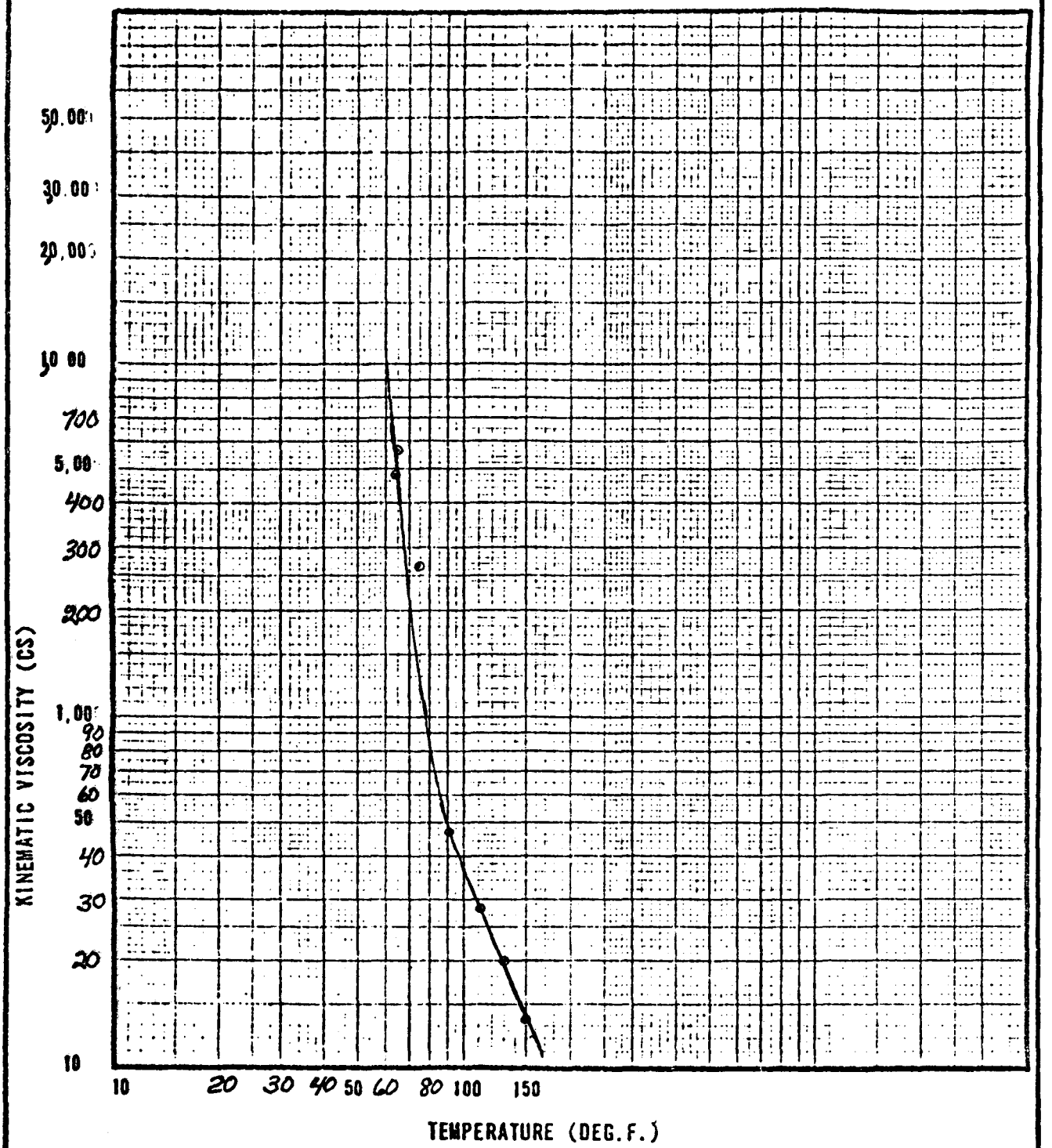
By W.C. Source Oily

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
0935	71°	Fluid
1000	66°	Fluid
1010	61°	Fluid
1020	57°	Fluid
1034	54°	no movement



FROM 55 GAL DRUM

SAMPLE CONTAINED NALCO #5351, 0.05 Gm/100 Mls.

OCCIDENTAL RETORT #6

WILLIAMS BROTHERS ENGINEERING COMPANY

A Resource Sciences company

TULSA, OKLAHOMA

CRUDE OIL VISCOSITY VS. TEMPERATURE

539

WBEC DATA

JOB 4359 | EXHIBIT NO. 11/24/80 | REV.

LAWLER

Account No. 4358 Sample No. 55 gal drum + Nalco

Date 11-18-80 Source Oxy

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

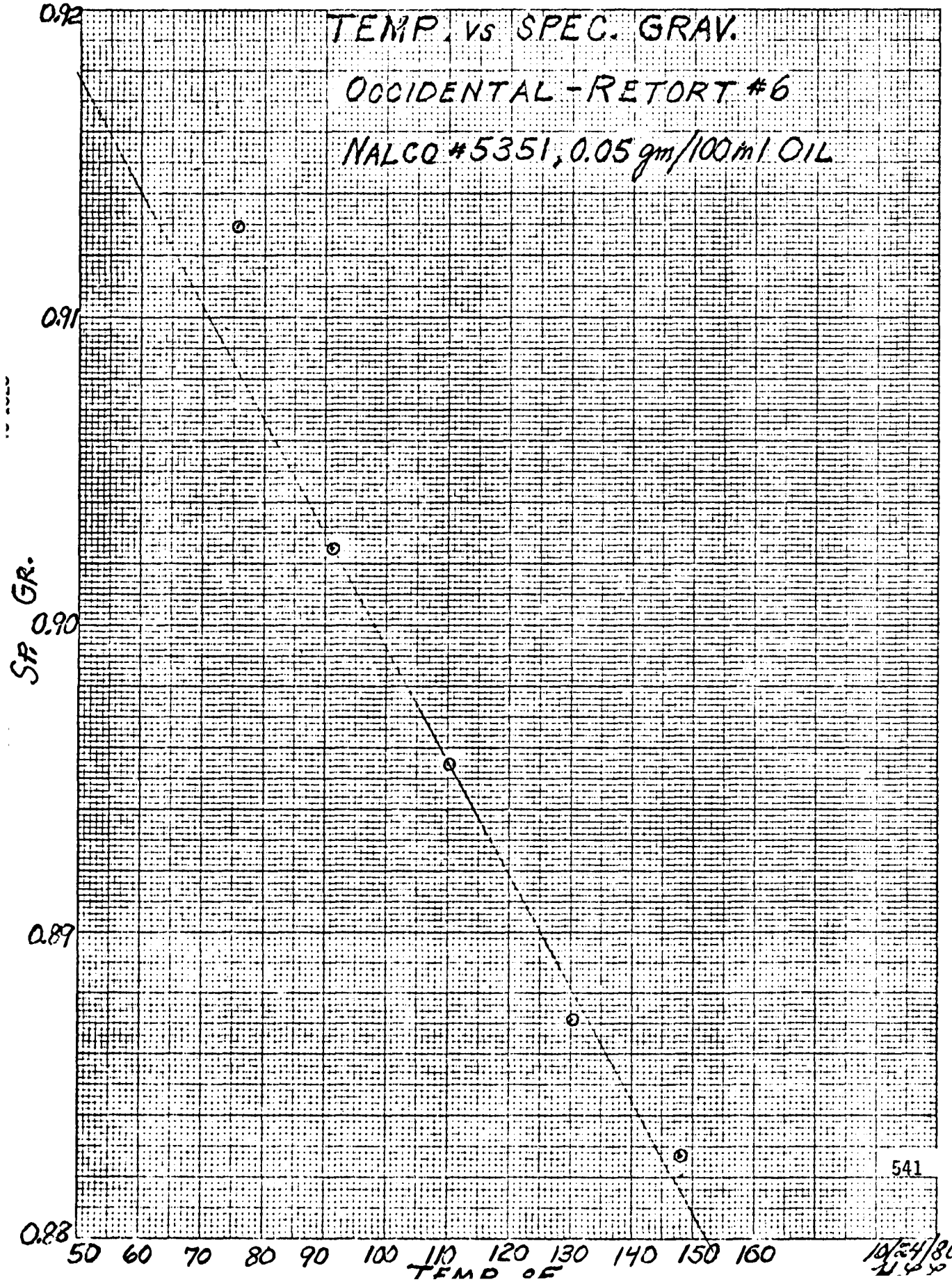
A.P.I. GRAVITY

Temperature °C	Hydrometer Reading	
64.5° C 148.1°F	28.8	0.8827 S.G.
54.5° C 130.1°F	28.0	0.8871 "
43.1° C 109.6°F	26.5	0.8955 "
33.0° C 91.4°F	25.3	0.9025 "
24.5° C 76.1°F	23.5	0.9129 "

Remarks:

5351 Nalco added at the Rate of 0.05 gms per 100 ml.

Signed _____


TEMP. Vs SPEC. GRAV.
OCCIDENTAL - RETORT #6
NALCO #5351, 0.05 gm/100ml OIL
SP GR.
0.92
0.91
0.90
0.89
0.88
50 60 70 80 90 100 110 120 130 140 150 160
TEMP °F
541

J. Burnett

Account No. 4358 Sample No. 5 Gal drum + Nalco

Date 11-18-80 Source Oxy

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

A.P.I. GRAVITY

Temperature °C	Hydrometer Reading
64.5° C	28.8
54.5° C	28.0
43.1° C	26.5
33.0° C	25.3
24.5° C	23.5

Remarks:

5351 Nalco added at the rate of 0.05 gms per 100 ml.

Signed _____

DICK BURNETT

Date 11-13-80 Sample No. 55 gal Drum # 5351 Nalco

By WLC 14358 Source Oxy Ref. 6

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
1300	88°	Fluid
1315	79°	Fluid
1336	70°	Fluid
1348	63°	Fluid
1355	60°	Fluid
1402	58°	slight movement
1408	57°	" "
1415	55°	No Movement

.05 gm of 5351 Nalco per 100 ml. of shale oil

Date 11-12-80 Sample No. 55 gal. Drum

By W.C. Source Ogle

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
0950	64°	Fluid
1000	62°	Fluid
1010	59°	Fluid
1020	56°	Fluid
1034	51°	Fluid
1048	48°	Fluid
1054	47°	Fluid
1100	46°	Fluid
1114	45°	Slight movement
1121	44°	" "
1130	42°	no movement

LAWLER

Date 11-12-80 Sample No. Gel. Cons #4

By W.C. Source Oily

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
0935	71°	Fluid
10.00	66°	Fluid
1010	61°	Fluid
1020	57°	Fluid
1034	54°	no movement

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

11-17-80

PREPARED BY: W.C.

SYSTEM: B-Cup

MATERIAL: Shale Oil

SOURCE: Oxy

WEIGHT PER CENT SOLIDS — NOMINAL ___ % ACTUAL ___ %

TEMPERATURES — BEFORE 65.1°F 18.4 °C ☐F ☐C — AFTER 63.5°F 17.5 °C ☐F ☐C

ADDITIVES: 5351 Nalco 0.05 [illegible] 100 ml. S.G. 18.5

SPEED SET	UP	DOWN	AVERAGE		REMARKS
1	23.0	17.5	17.8		
2	25.2	18.9	18.3		Sample taken from 55 gal.
3	28.2	20.6	19.3		drum & Rotot 6
4	30.3	22.9	19.7		
5	33.2	25.8	22.7	15.7	
6	39.4	31.5	27.7	20.2	
7	45.2	37.4	32.9	25.1	
8	51.7	44.6	39.3	31.1	
9	60.6	54.6	48.3	39.4	
10	70.5	67.3	57.7	49.8	
11	93.1		71.1	69.3	
12			91.1		
13					
14					
15					

DRY CUPS

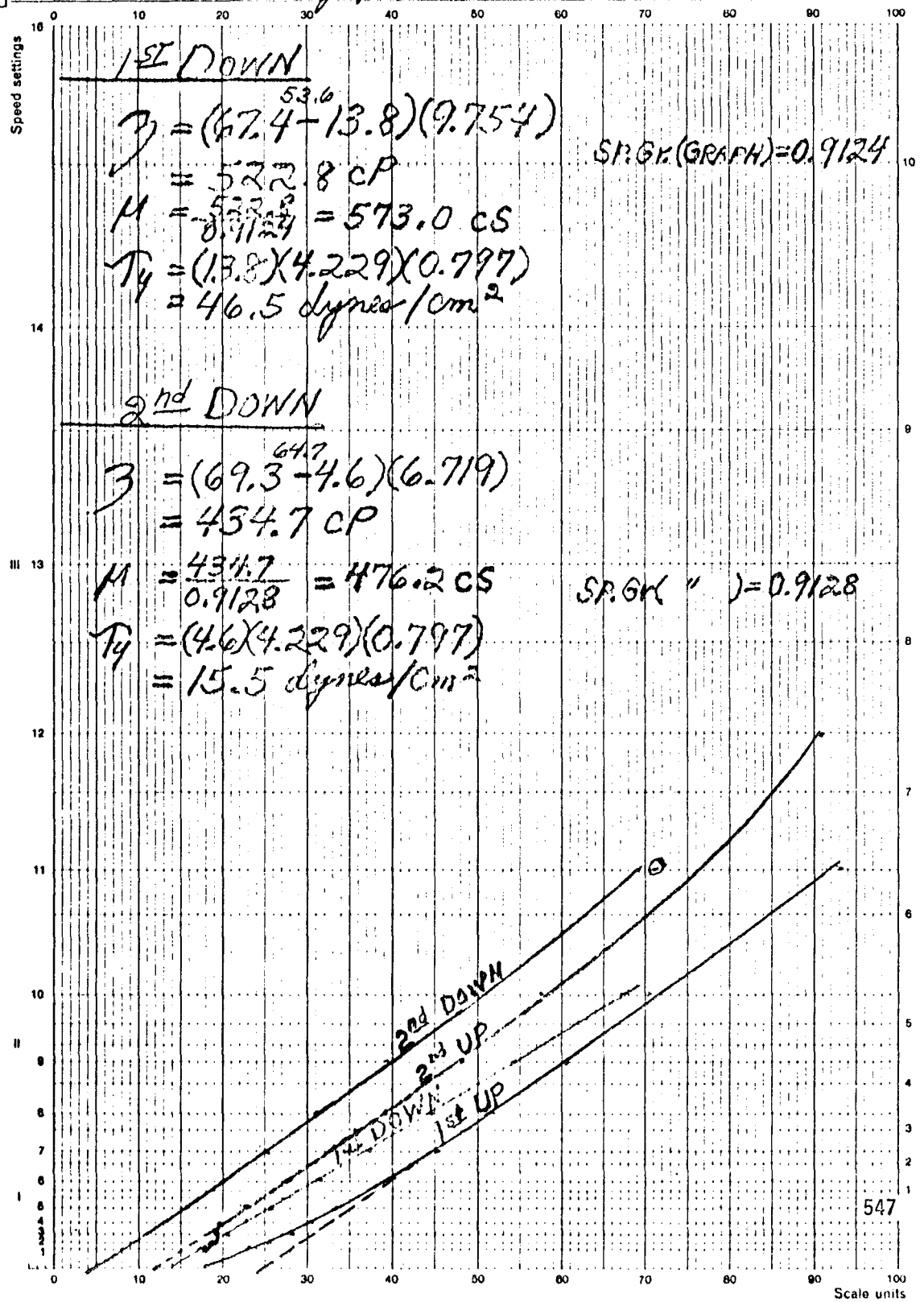
BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	___ GMS	GROSS SLURRY WEIGHT	___ GMS
LESS: CUP #___ TARE	___ GMS	LESS: CUP #___ TARE	___ GMS
NET SLURRY WEIGHT	___ GMS	NET SLURRY WEIGHT	___ GMS
GROSS SOLID WEIGHT	___ GMS	GROSS SOLID WEIGHT	___ GMS
LESS: CUP #___ TARE	___ GMS	LESS: CUP #___ TARE	___ GMS
NET SOLID WEIGHT	___ GMS	NET SOLID WEIGHT	___ GMS
546 NET SOLID WEIGHT / NET SLURRY WEIGHT ___ × 100 = ___ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT ___ × 100 = ___ % WT.	

SLU-269

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL B-CUP — DATE 11/17/80
NALCO #5351 — 65.1-63.5°F — SHALE OIL RT IN 6
0.05 gm/100ml — 55 GAL DRUM



1ST DOWN

$\theta = (67.4 - 13.8)(9.754)$ (53.6)

$= 522.8$ cP

$\mu = \frac{522.8}{0.9124} = 573.0$ cs

$T_y = (13.8)(4.229)(0.797)$

$= 46.5$ dynes/cm^2

SP. GR. (GRAPH) = 0.9124

2nd DOWN

$\theta = (69.3 - 4.6)(6.719)$ (64.7)

$= 434.7$ cP

$\mu = \frac{434.7}{0.9128} = 476.2$ cs

$T_y = (4.6)(4.229)(0.797)$

$= 15.5$ dynes/cm^2

SP. GR. (") = 0.9128

547

LCO-380

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 11-17-80

PREPARED BY W.C.

SYSTEM B-Cup

MATERIAL Shale Oil

SOURCE Ory

ADDITIVES 5351 Nalco 0.05 gm per 100 ml.

WEIGHT PER CENT SOLIDS
NOMINAL — % | ACTUAL — %

TEMPERATURES
BEFORE 74.3°C 23.5 °F/°C | AFTER 23.5 °F/°C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1	4.1	—		
2	5.1	3.2		Sample taken from 55 gal. drum
3	6.1	4.0		
4	7.5	5.1		
5	9.2	6.5		
6	12.2	9.0		
7	15.4	11.8		
8	19.1	15.1		
9	24.2	19.8		
10	30.3	25.6		
11	41.8	36.6		
12	53.8	48.5		
13	68.1	63.1		
14	87.0	84.3		
15	—	—		

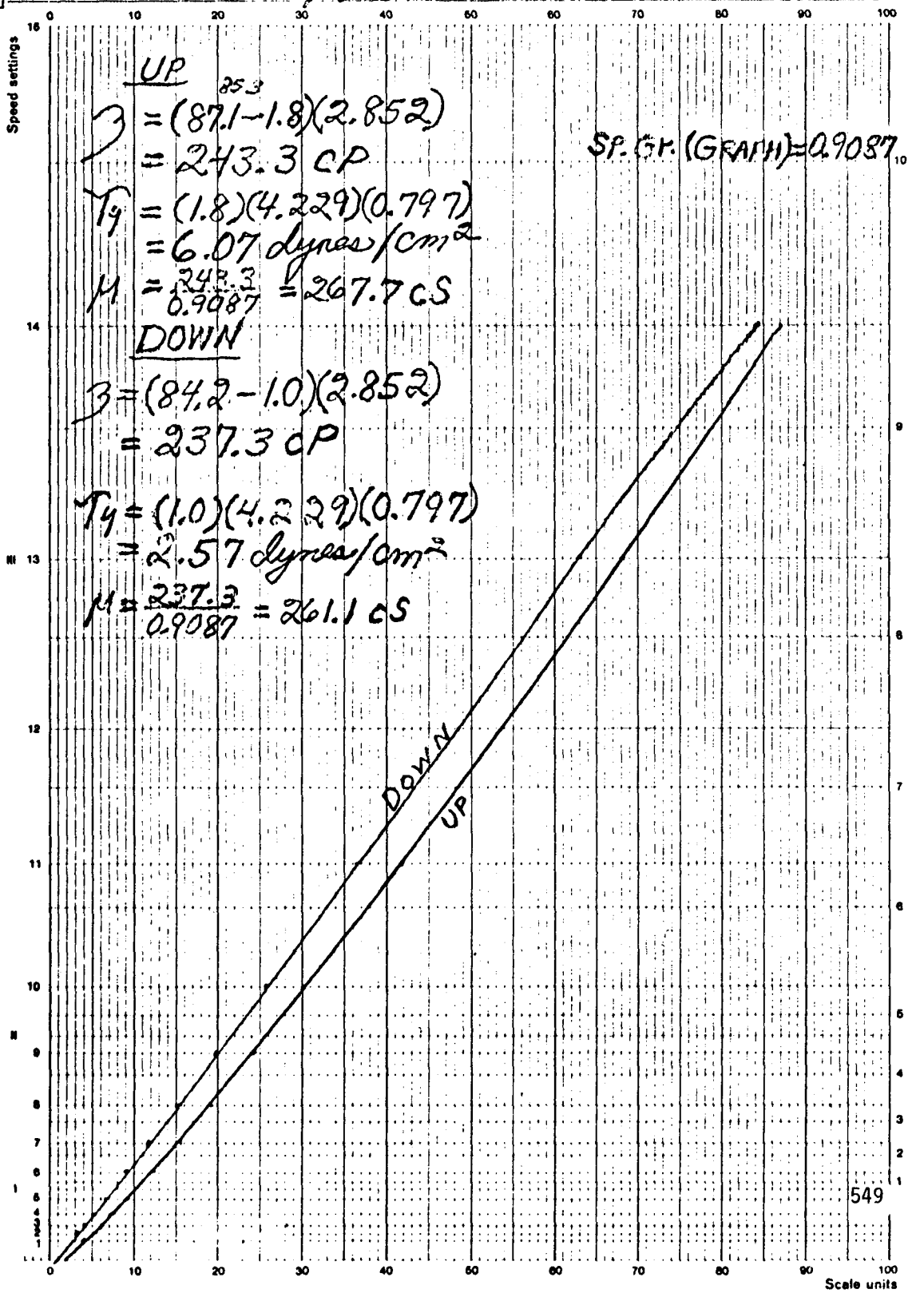
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN:	☐AM ☐PM	TIME PLACED IN OVEN:	☐AM ☐PM
GROSS SLURRY WEIGHT	_____ GMS	GROSS SLURRY WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SLURRY WEIGHT	_____ GMS	NET SLURRY WEIGHT	_____ GMS
GROSS SOLID WEIGHT	_____ GMS	GROSS SOLID WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SOLID WEIGHT	_____ GMS	NET SOLID WEIGHT	_____ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL	B-CUP		HLP	11/20/85
NALCO #5351			SHALE OIL - RT #6	
0.05 gm/100 ml		77.3	55 GAL DRUM	



UP

$\eta = (87.1 - 1.8)(2.852)$

$= 243.3$ cP

$\tau_y = (1.8)(4.229)(0.797)$

$= 6.07$ dynes/cm²

$\mu = \frac{243.3}{0.9087} = 267.7$ cS

DOWN

$\eta = (84.2 - 1.0)(2.852)$

$= 237.3$ cP

$\tau_y = (1.0)(4.229)(0.797)$

$= 2.57$ dynes/cm²

$\mu = \frac{237.3}{0.9087} = 261.1$ cS

SP. GR. (GRAPH) = 0.9087

549

SLU-360

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 1358 | DATE 11-13-80

PREPARED BY W.C.

SYSTEM A-Cup

MATERIAL Shale Oil

SOURCE Occidental

WEIGHT PER CENT SOLIDS
NOMINAL ____ % | ACTUAL ____ %

TEMPERATURES
BEFORE 32.9° ☐F ☐C | AFTER 32.7° ☐F ☐C

ADDITIVES 5351 Nalco 0.05 gm per 100 ml.

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				Sample taken from 55 gal. drum of Retort 6
2				
3	4.1	4.1	4.1	
4	5.5	5.5	5.5	
5	7.3	7.3	7.3	
6	10.5	10.5	10.5	
7	14.2	14.3	14.25	
8	18.7	18.7	18.70	
9	25.0	25.1	25.05	
10	33.1	33.1	33.10	
11	48.3	48.3	48.30	
12	65.4	65.3	65.35	
13	86.5	86.5	86.50	
14	off-scale			
15				

DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN:	☐AM ☐PM	TIME PLACED IN OVEN:	☐AM ☐PM
GROSS SLURRY WEIGHT	____ GMS	GROSS SLURRY WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SLURRY WEIGHT	____ GMS	NET SLURRY WEIGHT	____ GMS
GROSS SOLID WEIGHT	____ GMS	GROSS SOLID WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SOLID WEIGHT	____ GMS	NET SOLID WEIGHT	____ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT	____ × 100 = ____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	____ × 100 = ____ % WT.

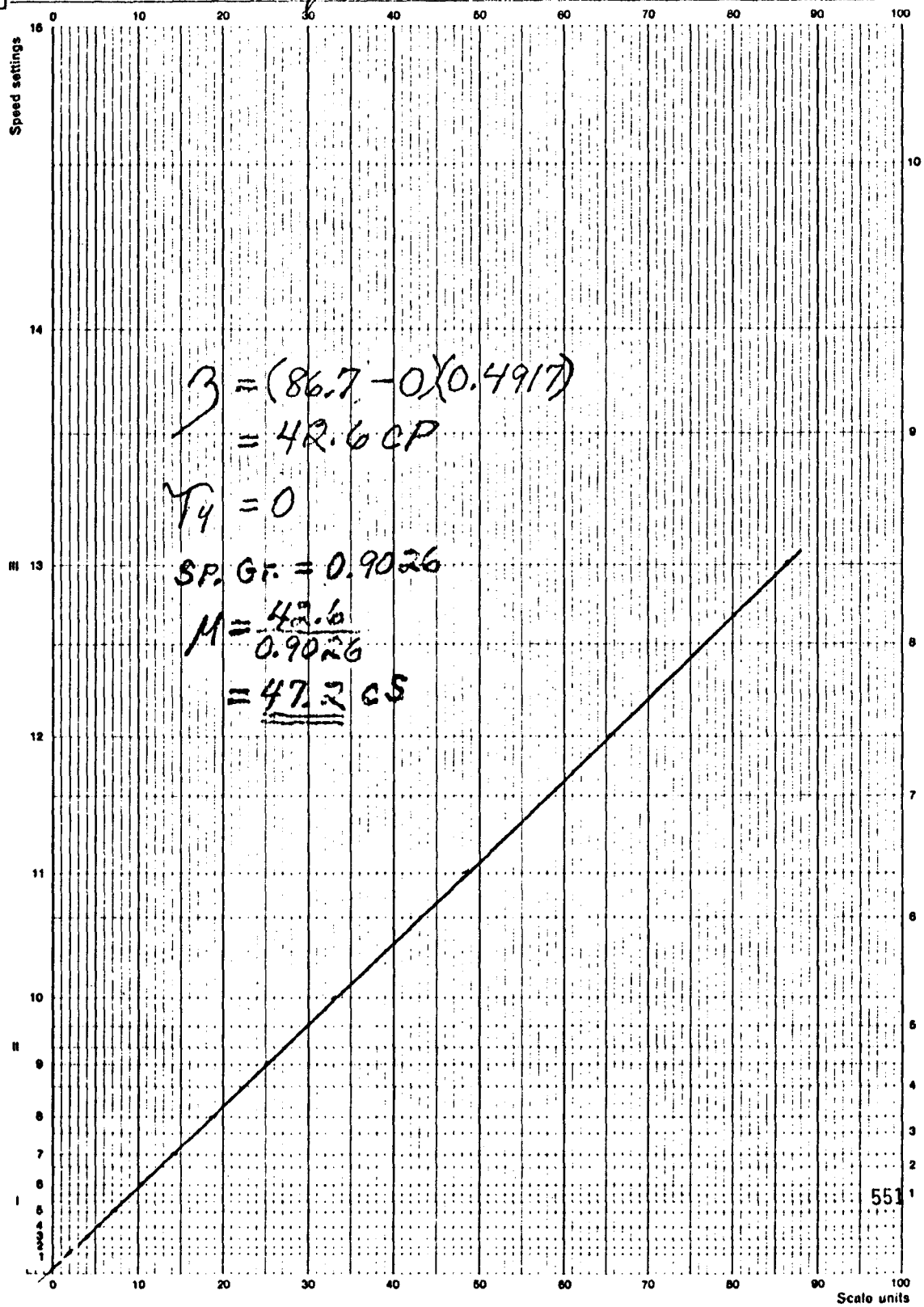
550

SLU-269

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDETAL	A-CUP		RLR	11/13/80
NALCO #5351 0.05 gm/100 ml	91.2-90.8°F	SHALE OIL-RT #6 55 GAL. DRUM		



$$\beta = (86.7 - 0)(0.4917)$$
$$= 42.6 \text{ cp}$$

$$\tau_y = 0$$

Sp. Gr. = 0.9026

$$\mu = \frac{42.6}{0.9026}$$
$$= 47.2 \text{ cs}$$

LO-380

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 DATE 11-13-80

PREPARED BY W.C.

SYSTEM A-Cup

MATERIAL Shale Oil

SOURCE Occidental

WEIGHT PER CENT SOLIDS NOMINAL — % ACTUAL — %

TEMPERATURES BEFORE 111.2°F 44.0°C AFTER 110.7°F 43.7°C

ADDITIVES 5351 Nalco 0.05 ml per 100 ml.

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				Sample taken from 55 gal. drum by Retort 6
2				
3				
4				
5	4.1	4.2	4.15	
6	5.9	6.1	6.00	
7	8.0	8.2	8.10	
8	10.7	10.8	10.75	
9	14.3	14.5	14.40	
10	19.0	19.3	19.15	
11	27.9	28.2	28.05	
12	38.0	38.4	38.20	
13	50.6	50.9	50.75	
14	68.7	69.0	68.85	
15	92.4		92.4	

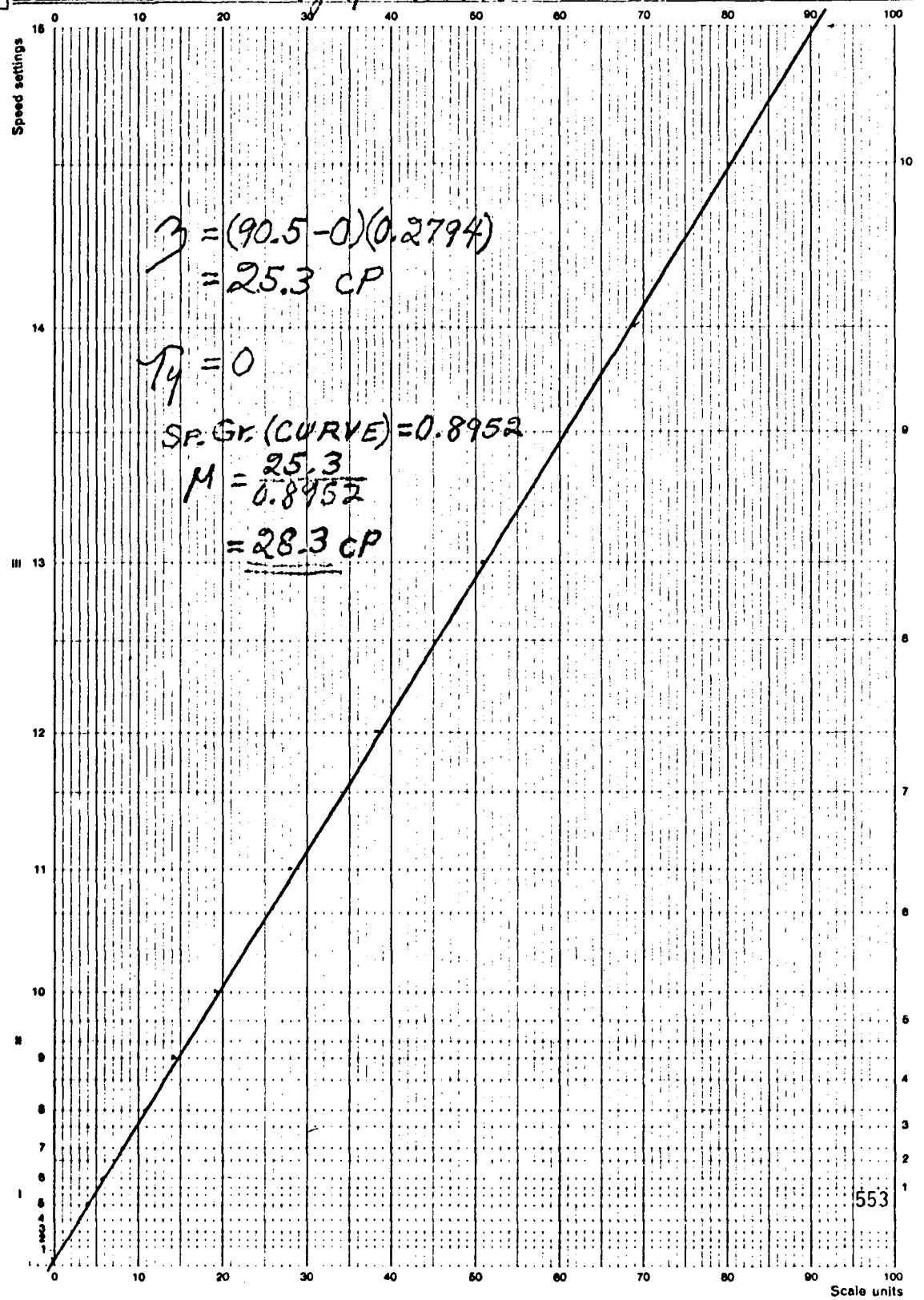
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN:	☐AM ☐PM	TIME PLACED IN OVEN:	☐AM ☐PM
GROSS SLURRY WEIGHT	_____ GMS	GROSS SLURRY WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SLURRY WEIGHT	_____ GMS	NET SLURRY WEIGHT	_____ GMS
GROSS SOLID WEIGHT	_____ GMS	GROSS SOLID WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SOLID WEIGHT	_____ GMS	NET SOLID WEIGHT	_____ GMS
552			
NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	FIELD	DATE	DATE
OCCIDENTAL	A-CUP		H2O	11/13/80
NALCO #5351			SHALE OIL - RT #6	
0.05 gm/100ml	111.2°-110.7° F		55 GAL DRUM	



$\tau = (90.5 - 0)(0.2794)$

$= 25.3$ cP

$\tau_y = 0$

Sp. Gr. (CURVE) $= 0.8952$

$\mu = \frac{25.3}{0.8952}$

$= 28.3$ cP

SLO-380

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4135-8 | DATE 11-13-80

PREPARED BY W.C.

SYSTEM A-Cup

MATERIAL Shale Oil

SOURCE Occidental

WEIGHT PER CENT SOLIDS — NOMINAL — % | ACTUAL — %

TEMPERATURES — BEFORE 54.2 °F/°C | AFTER 54.0 °F/°C

ADDITIVES 5351 Nalco 0.05 gm per 100 ml

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				Sample from 55 gal. drum A Total 6
2				
3				
4				
5				
6	4.0	4.0	4.0	
7	5.4	5.4	5.4	
8	7.2	7.3	7.25	
9	9.7	9.7	9.7	
10	12.9	12.9	12.9	
11	18.9	18.9	18.9	
12	25.9	25.9	25.9	
13	34.6	34.6	34.6	
14	47.2	47.1	47.15	
15	63.5		63.5	

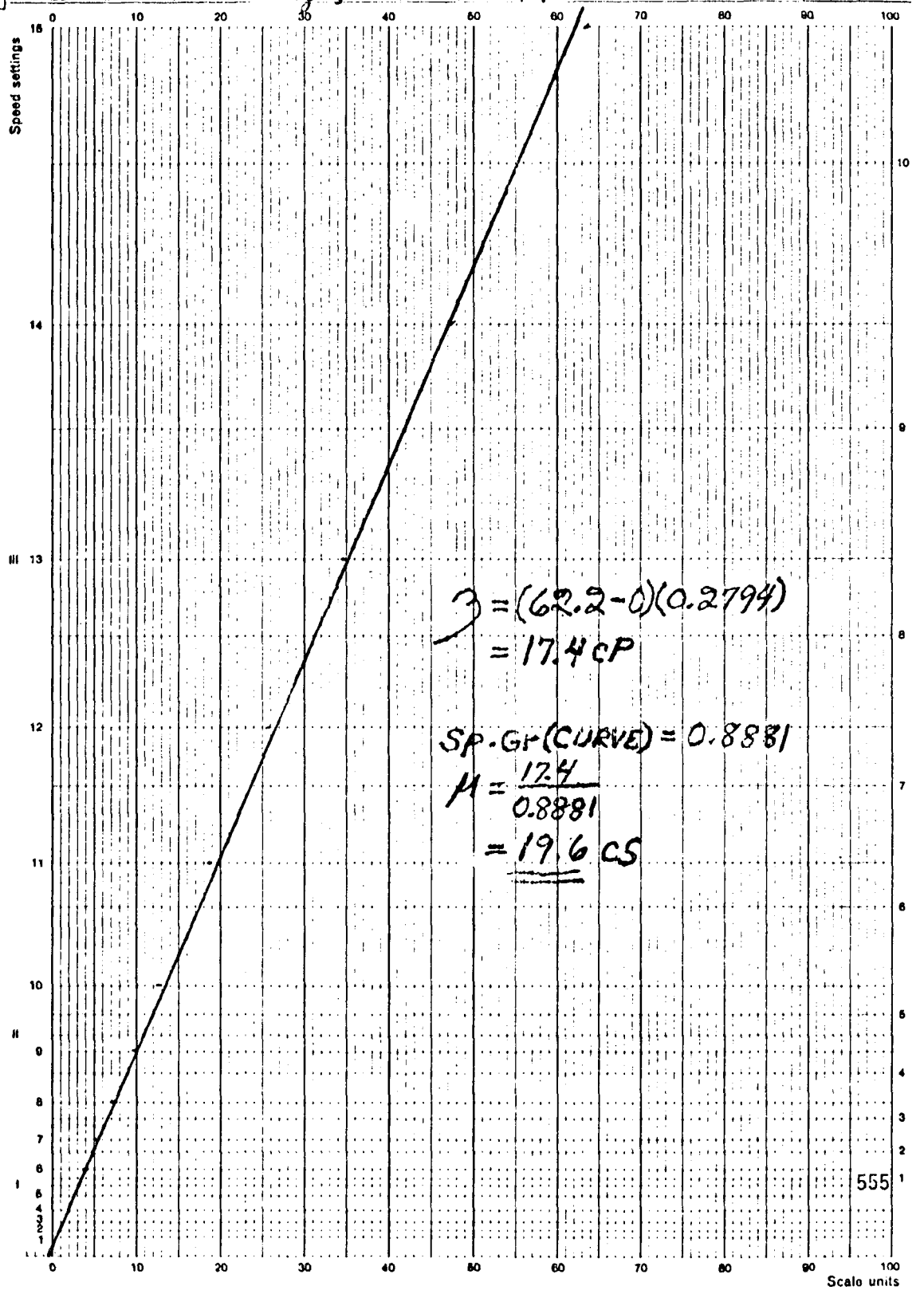
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN:	☐AM ☐PM	TIME PLACED IN OVEN:	☐AM ☐PM
GROSS SLURRY WEIGHT	GMS	GROSS SLURRY WEIGHT	GMS
LESS: CUP #___ TARE	GMS	LESS: CUP #___ TARE	GMS
NET SLURRY WEIGHT	GMS	NET SLURRY WEIGHT	GMS
GROSS SOLID WEIGHT	GMS	GROSS SOLID WEIGHT	GMS
LESS: CUP #___ TARE	GMS	LESS: CUP #___ TARE	GMS
NET SOLID WEIGHT	GMS	NET SOLID WEIGHT	GMS
554 NET SOLID WEIGHT / NET SLURRY WEIGHT ___ x 100 = ___ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT ___ x 100 = ___ % WT.	

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL	A-CUP	H.R.C	11/13/80
NALCO #5351		SHALE OIL-RT#6	
0.05 gm/100 ml	122.6-127.2	55 GAL DRUM	



$\mu = (62.2-0)(0.2794)$

$= 17.4$ cP

SP. GR (CURVE) $= 0.8881$

$\mu = \frac{17.4}{0.8881}$

$= 19.6$ cS

LAWLER

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO.	DATE
4358	11-13-80

PREPARED BY: W. C.

SYSTEM: A-Cup

MATERIAL: Shale Oil

SOURCE: Occidental

WEIGHT PER CENT SOLIDS: NOMINAL ——— % ACTUAL ——— %

TEMPERATURES: BEFORE 150.3 65.7 °F °C | AFTER 147°F 65.0 °F °C

ADDITIVES: 5351 Nalco 0.05 gm per 100 ml

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				Sample from 55 gal. drum
2				of Retort 6
3				
4				
5				
6				
7	3.6	3.5	3.55	
8	4.7	4.8	4.75	
9	6.4	6.5	6.45	
10	8.6	8.7	8.65	
11	12.9	12.9	12.9	
12	17.6	17.7	17.65	
13	23.7	23.8	23.75	
14	32.5	32.5	32.50	
15	44.2		44.20	

DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN:	☐AM ☐PM	TIME PLACED IN OVEN:	☐AM ☐PM
GROSS SLURRY WEIGHT	_____ GMS	GROSS SLURRY WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SLURRY WEIGHT	_____ GMS	NET SLURRY WEIGHT	_____ GMS
GROSS SOLID WEIGHT	_____ GMS	GROSS SOLID WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SOLID WEIGHT	_____ GMS	NET SOLID WEIGHT	_____ GMS

556

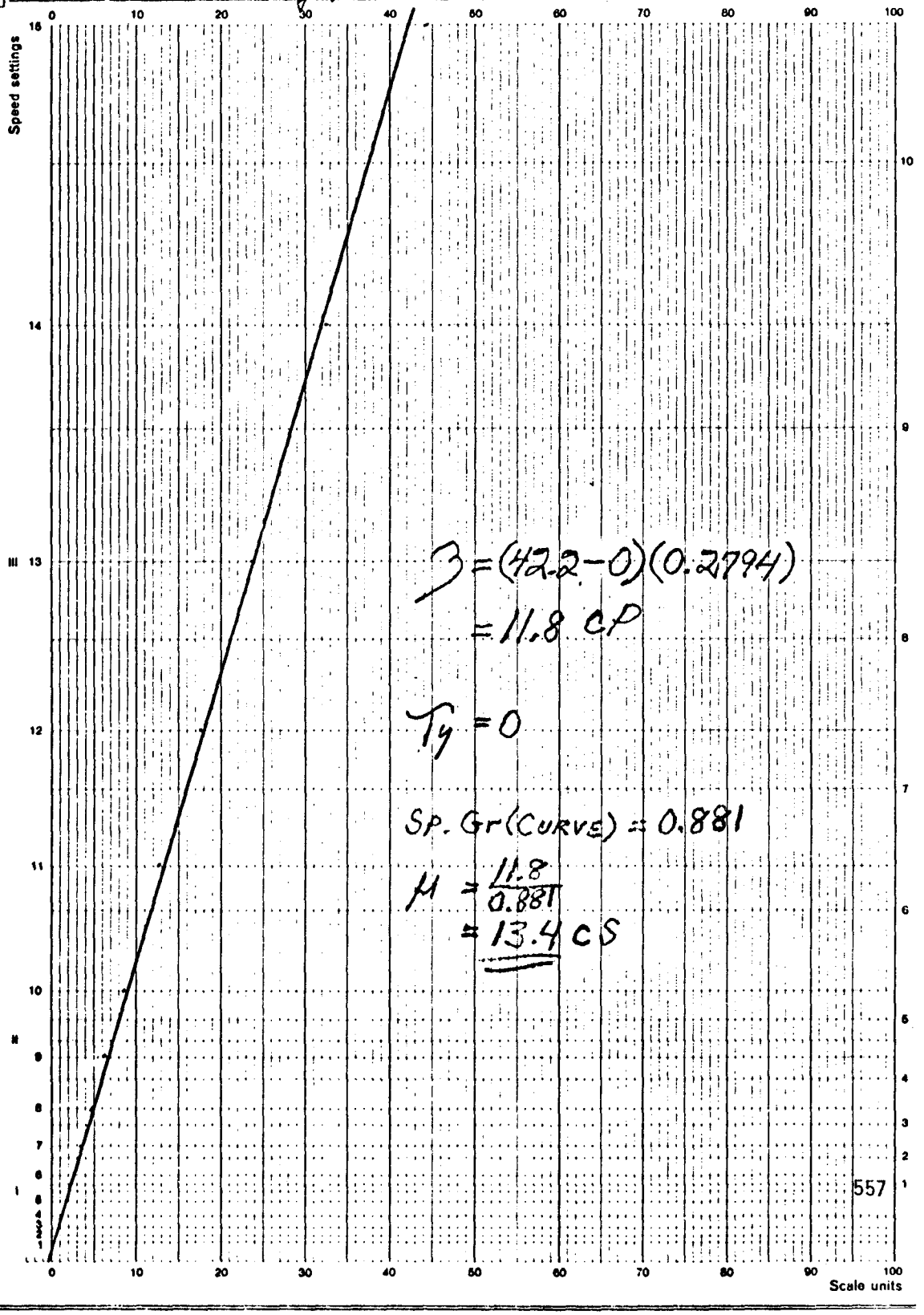
NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

OCCIDENTAL NALCO #5351 0.05 gm/100 ml	A-CUP 150.3-149.0	HRP SHALE OIL-RT #6 55 GAL DRUM	11/19/80



$$\beta = (42.2 - 0)(0.2794)$$
$$= 11.8 \text{ cP}$$

$$\tau_y = 0$$

$$\text{Sp. Gr(Curve)} = 0.881$$

$$\mu = \frac{11.8}{0.881}$$
$$= 13.4 \text{ cS}$$

557

SLO-380

Date 11-26-80

By W.C.

Sample No. B.0.05gm 5351 / 100ml Shale Oil 80°F

Source Org

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

67° − 33° = − 34°F drop

Time	Temperature °F	Condition of Sample
1010	74°	Fluid
1020	70°	Fluid
1033	66°	Fluid
1041	63°	Fluid
1048	60°	Fluid
1055	57°	Fluid
1100	56°	Fluid
1110	54°	Fluid
1122	52°	Fluid
1133	50°	Fluid
1140	49°	Fluid
1500	47°	Fluid
1525	46°	Fluid
1545	44°	Fluid
1605	40°	Fluid
1615	39°	Fluid
1630	38°	Fluid
1647	37°	Fluid
1706	35°	Slight movement
1717	33°	No movement

Sample B. 0.05gm of 5351 Oako in 100ml. of Shale oil at 80°F, Heated to 150°F for mixing

Date 11-26-80

By W.C.

Sample No. B. 0.05 gm 5351 / 100 ml Shale Oil 80°F

Source Orig

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

67° − 33° = − 34°F drop

Time	Temperature °F	Condition of Sample
1010	74°	Fluid
1020	70°	Fluid
1033	66°	Fluid
1041	63°	Fluid
1048	60°	Fluid
1055	57°	Fluid
1100	56°	Fluid
1110	54°	Fluid
1122	52°	Fluid
1133	50°	Fluid
1140	49°	Fluid
1500	47°	Fluid
1525	46°	Fluid
1545	44°	Fluid
1605	40°	Fluid
1615	39°	Fluid
1630	38°	Fluid
1647	37°	Fluid
1706	35°	Slight movement
1717	33°	no movement

559

Sample B. 0.05 gm of 5351 Oako in 100 ml. of Shale oil at 80°F, Heated to 150°F for mixing

4358

Date 11-26-80 Sample No. A. Standard

By W.C. Source Ohio

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °OF	Condition of Sample
1010	73°	Fluid
1020	71°	Slight movement
1033	67°	no movement
	Standard Oil Sample	+67°F

Sample A. 100ml. of Shak oil with no additive. Treated same as samples B.C.D. Heated to 150°F

4358

Date 11-26-80 Sample No. A. Standard

By W.C. Source Oil

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °F	Condition of Sample
1010	73°	Fluid
1020	71°	Slight movement
1033	67°	no movement
	Standard Pour + 67°F	

Sample A. 100ml. of Shale oil with no additive. Treated same as Samples B.C.D. Heated to 150°F

5351

Date 11-26-80

By W.C.

Sample No. C.05gm 5351/2cc Tolu... 100 ml. Shale oil 80°F

Source Opal

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

67°-34°=-33°F drop

Time	Temperature °F	Condition of Sample
1010	73°	Fluid
1020	69°	Fluid
1033	64°	Fluid
1041	61°	Fluid
1048	58°	Fluid
1055	55°	Fluid
1100	54°	Fluid
1110	52°	Fluid
1122	49°	Fluid
1133	48°	Fluid
1410	47°	Fluid
1500	45°	Fluid
1525	43°	Fluid
1545	41°	Fluid
1605	38°	Fluid
1615	36°	Slight movement
1630	35°	Slight movement
1647	34°	no movement

562

Sample C. 0.05gm of 5351 Nalco plus 2cc.s of Toluene in 100ml. of shale oil at 80°F Heated to 130°F to add 5351 Nalco and mix

5351

Date 11-26-80

By M.C.

Sample No. C-.05 gm 5351/2cc Tolu... 100 ml. Shale oil 80°F

Source Ogden

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

67°-34°=-33°F drop

Time	Temperature °F	Condition of Sample
1010	73°	Fluid
1020	69°	Fluid
1033	64°	Fluid
1041	61°	Fluid
1048	58°	Fluid
1055	55°	Fluid
1100	54°	Fluid
1110	52°	Fluid
1122	49°	Fluid
1133	48°	Fluid
1440	47°	Fluid
1500	45°	Fluid
1525	43°	Fluid
1545	41°	Fluid
1605	38°	Fluid
1615	36°	Slight movement
1630	35°	Slight movement
1647	34°	no movement

Sample C. .05 gm of 5351 Nalco plus 2cc of Toluene in 100ml of shale oil at 80°F. Heated to 130°F to add 5351 Nalco and mix

Date 11-26-80

By W.C.

Sample No. 0. 2cc Toluene/100ml Shale Oil @ 80°F

Source Oil

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °a/F	Condition of Sample
1010	73°	Fluid
1020	69°	Slight movement
1033	64°	no movement
	67 - 64 = -3°F drop	

Sample 0. 2cc's of Toluene in 100 ml. of Shale oil at 80.°F

Heated to 130°F

#358

Date 11-26-80 Sample No. 0. 2cc Toluene/100cc. Shale Oil 80°F

By W.C. Source Oil

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °a/F	Condition of Sample
1010	73°	Fluid
1020	69°	Slight movement
1033	64°	no movement
	67 - 64 = -3°F drop	

Sample 0. 2cc s of Toluene in 100 ml. of Shale oil at 80.°F

Heated to 130°F

APPENDIX NO. 6

OCCIDENTAL SHALE OIL

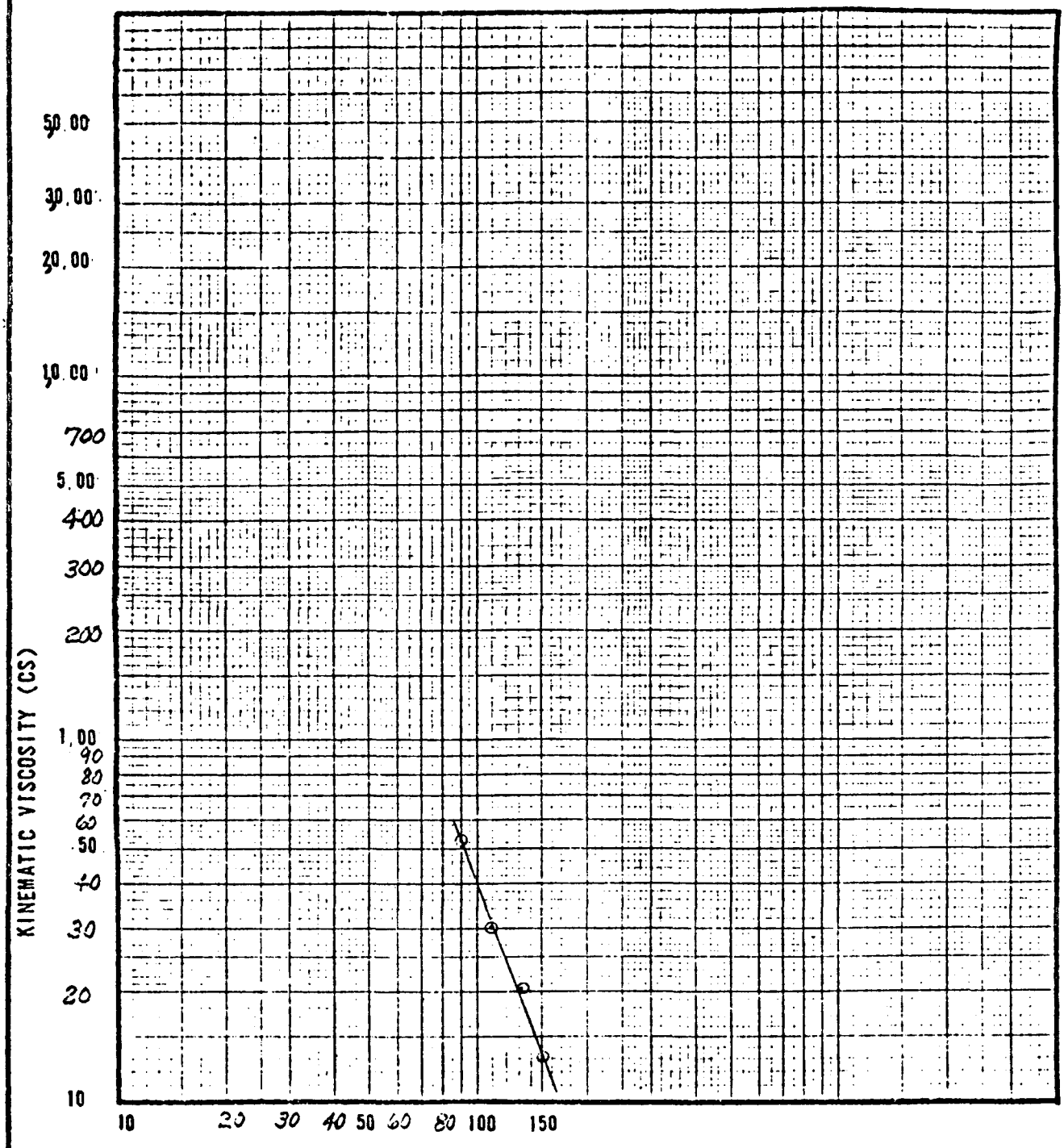
RETORT NO. 6

POUR POINT AND VISCOSITY

TEST DATA

December, 1980 Series

Additive Comparison Tests



FROM 55 GAL DRUM

FRESH SAMPLE HEATED 80° TO 130°F, 0.05 gms Nalco #5351 ADDED/100 ml OIL

OCCIDENTAL RETORT #6

WILLIAMS BROTHERS ENGINEERING COMPANY
A Resource Sciences company
TULSA, OKLAHOMA

CRUDE OIL VISCOSITY
VS.
TEMPERATURE

569

WREC DATA

JOB 4358	EXHIBIT NO. 12/13/80	REV.

5351

Date 12-11-80 Sample No. 55 gal. drum 0.05 gm Nalco

By W.C. Source Oxy Shale Tr. Co.

Williams Brothers Engineering Company

Fluid Dynamics Research Center Laboratory

POUR POINT DETERMINATION

Time	Temperature °C/F	Condition of Sample
0820	64°	Fluid
0850	58°	Fluid
0900	55°	Fluid
0915	51°	Fluid
0932	47°	Fluid
0947	43°	Fluid
1005	39°	Fluid
1015	38°	Fluid
1033	36°	Fluid
1045	35°	Fluid
1107	33°	Fluid
1125	32°	Fluid
1140	31°	Fluid
1255	27°	Slight movement
1315	25	No movement.

12-10-80
Sample taken from 55 gal. drum. 5351 Nalco was added at the rate of 0.05 gms per 100 ml. of Shale Oil. Started with 400 ml. of Oil at 80°F. added 0.20 gms of 5351 Nalco, then heated sample to 130°F for good mixing.

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 12-11-80

PREPARED BY W.C.

SYSTEM A-Cup

MATERIAL Shale Oil

SOURCE Oxy (Retort 6)

ADDITIVES 0.05 gms of 5351 Nalco per 100 ml. of Shale Oil

WEIGHT PER CENT SOLIDS — NOMINAL — % | ACTUAL — %

TEMPERATURES BEFORE 40.1°F 32.3°C ☐F ☐C | AFTER 31.8°F 32.1°C ☐F ☐C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				0.20 gms of 5351 to 400 ml. of Oil
2	3.7	3.5	3.6	at 80°F then heated to 130°F
3	4.7	4.6	4.65	for mixing. This was done on
4	6.2	6.2	6.2	12-10-80
5	8.3	8.2	8.25	
6	12.0	11.9	11.95	
7	16.2	16.1	16.15	
8	21.3	21.2	21.25	
9	28.5	28.3	28.4	
10	37.7	37.5	37.6	
11	54.8	54.7	54.75	
12	74.1	74.0	74.05	
13	97.8		97.8	
14	off-scale			
15				

DRY CUPS

BEFORE

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

AFTER

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

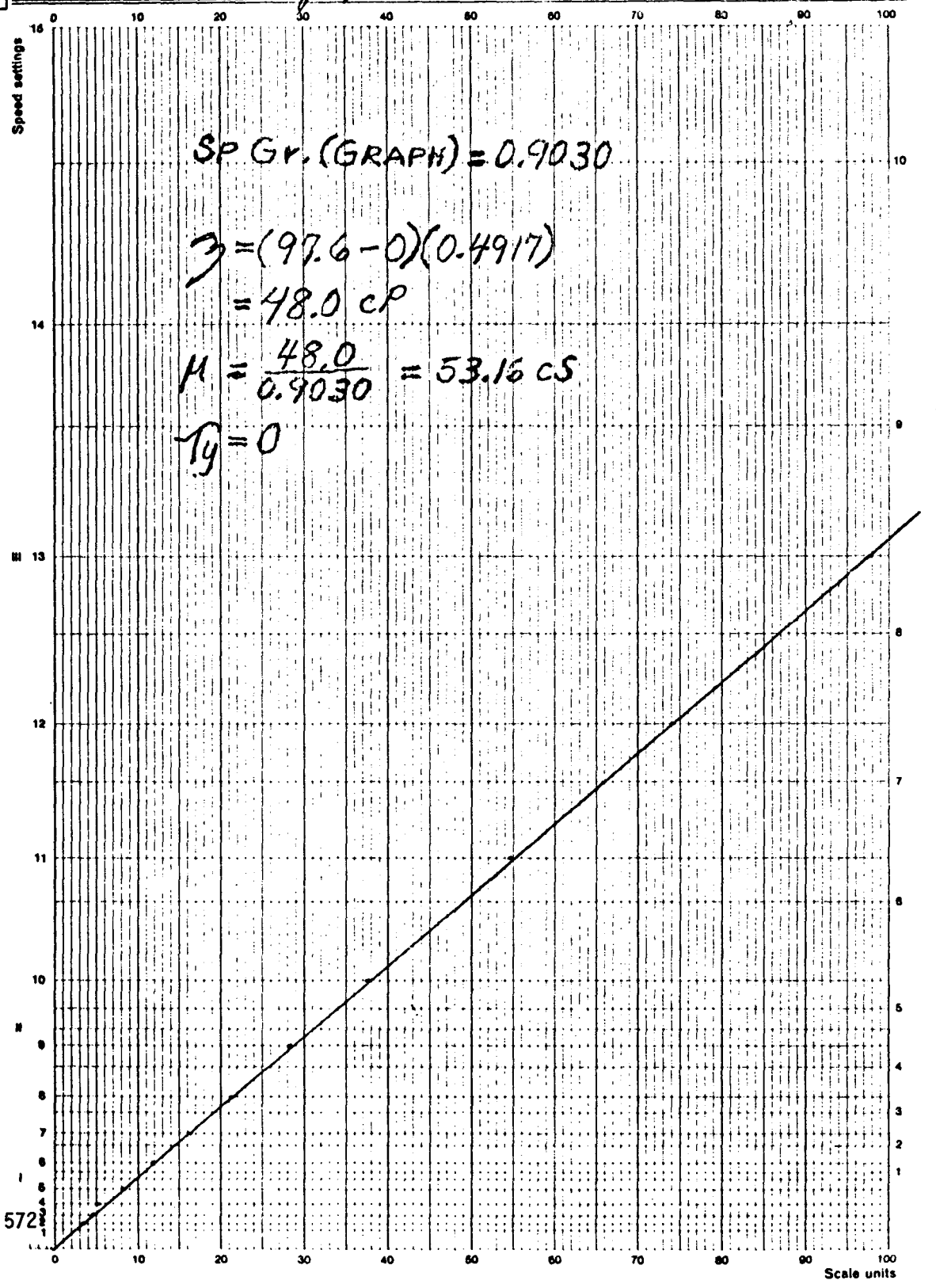
NET SOLID WEIGHT _____ GMS

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	BY	NAME	DATE
OCCIDENTAL WALCO #5351	A-CUP		HLR	12/11/80
0.05gm/100ml	90.1°-89.8°	SHALE OIL, RT #6	55 GAL DRUM	



$SP\ Gr.(GRAPH) = 0.9030$

$\theta = (97.6 - 0)(0.4917)$

$= 48.0\ cP$

$\mu = \frac{48.0}{0.9030} = 53.16\ cS$

$T_y = 0$

340

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 12-11-80

PREPARED BY W. C.

SYSTEM A - Oil

MATERIAL Shale Oil

SOURCE Occ (Retort 6)

ADDITIVES 0.05 gms of 5351 Nalco per 100 ml. of Shale Oil

WEIGHT PER CENT SOLIDS — NOMINAL — % | ACTUAL — %

TEMPERATURES — BEFORE 40.1°F 32.3°C | AFTER 31.8°F 32.1°C

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				0.20 gms of 5351 to 400 ml. Oil
2	3.7	3.5	3.6	at 80°F then heated to 130°F
3	4.7	4.6	4.65	for mixing. This was done on
4	6.2	6.2	6.2	12-10-80
5	8.3	8.2	8.25	
6	12.0	11.9	11.95	
7	16.2	16.1	16.15	
8	21.3	21.2	21.25	
9	28.5	28.3	28.4	
10	37.7	37.5	37.6	
11	54.8	54.7	54.75	
12	74.1	74.0	74.05	
13	97.8		97.8	
14	off - scale			
15				

DRY CUPS

BEFORE

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

AFTER

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

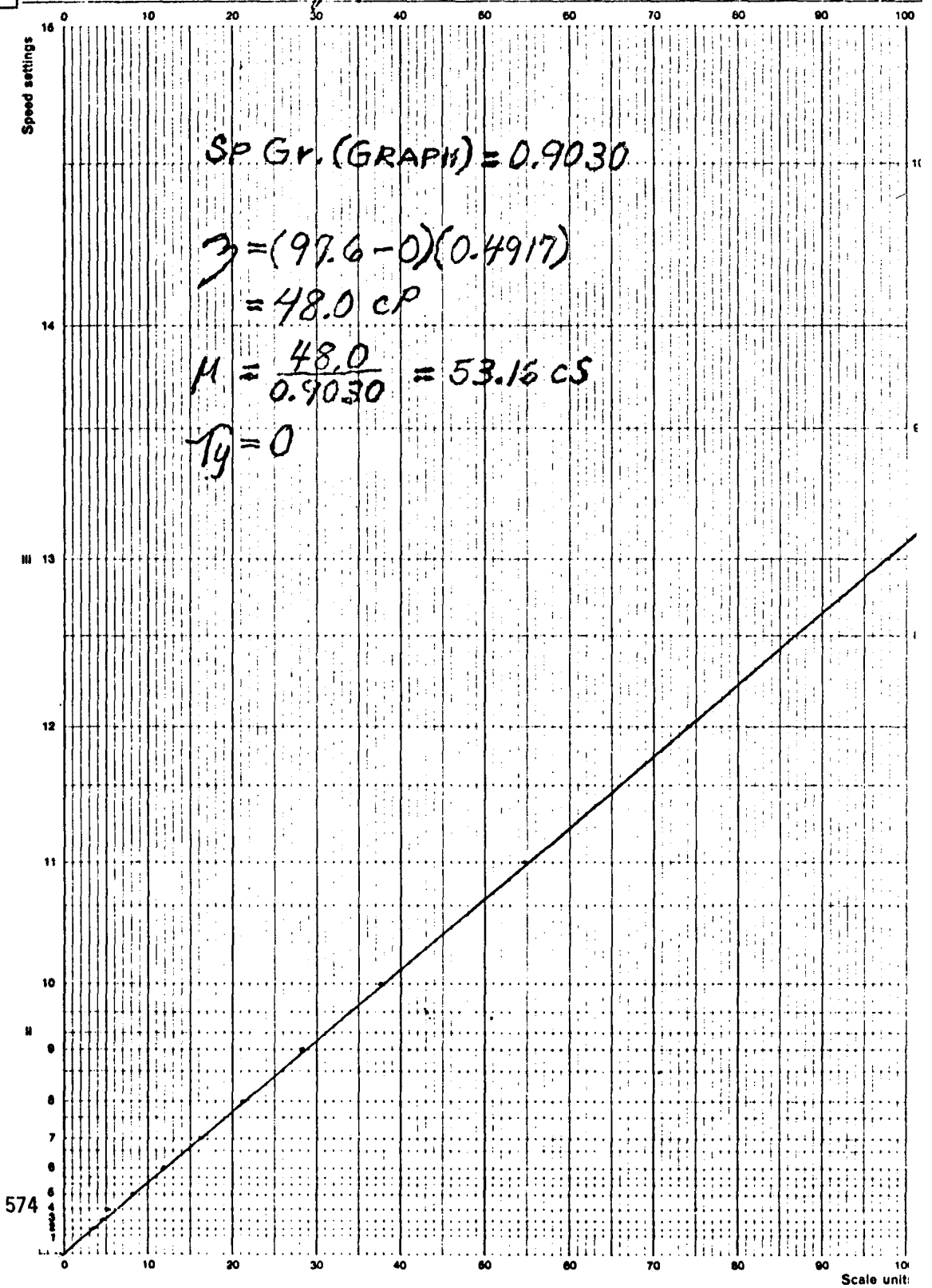
NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = 573 % WT.

ILU-200

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	FOR	NAME	DATE
OCCIDENTAL	A-CUP		HLP	12/11/20
TALCO #5351		SHALE OIL, RT #6		
0.05gm/100ml	90.1°-89.8	55 GAL DRUM		



574

LD-380

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 12-11-80

PREPARED BY W.S.

SYSTEM A-Cup

MATERIAL Shale Oil

SOURCE Occ (Retort-6)

WEIGHT PER CENT SOLIDS: NOMINAL ____ % | ACTUAL ____ %

TEMPERATURES: BEFORE 110.3°F / 43.5 °C ☐F ☐C | AFTER 110.1°F / 43.4 °C ☐F ☐C

ADDITIVES 0.05 gms A 5351 Nalco per 100 ml of Shale Oil

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				0.20 gms 5351 to 400 ml Shale Oil
2				at 80°F heated to 130°F to
3				mix good. This was done on
4	3.4	3.4	3.4	the 12-10-80
5	4.5	4.6	4.55	
6	6.5	6.7	6.6	
7	8.9	9.0	8.95	
8	11.7	11.9	11.80	
9	15.8	15.9	15.85	
10	20.9	21.0	20.95	
11	30.6	30.8	30.7	
12	41.6	41.8	41.7	
13	55.4	55.5	55.45	
14	75.1	75.3	75.2	
15	off scale		—	

DRY CUPS

BEFORE

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SOLID WEIGHT _____ GMS

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

AFTER

TIME PLACED IN OVEN: ☐AM ☐PM

GROSS SLURRY WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

NET SLURRY WEIGHT _____ GMS

GROSS SOLID WEIGHT _____ GMS

LESS: CUP #___ TARE _____ GMS

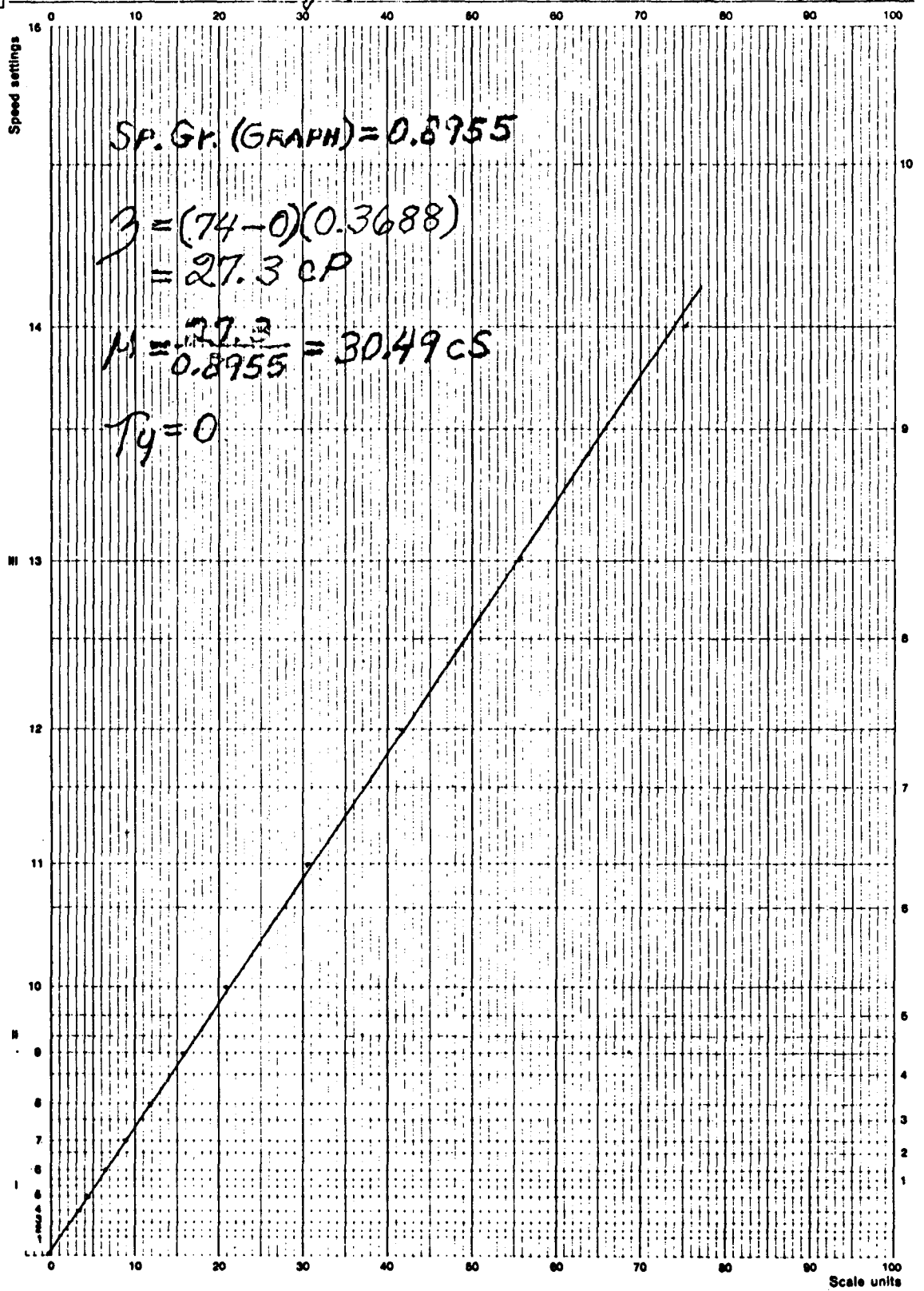
NET SOLID WEIGHT _____ GMS

NET SOLID WEIGHT / NET SLURRY WEIGHT _____ × 100 = _____ % WT.

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	PH	NAME	DATE
OCCIDENTAL NALCO #5331 0.05 gms/100 ml	A-CUP 110.3°-110.1°		HLP SHALE OIL, RT #6 55 GAL. DRUM	12/11/80



WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO.	DATE
4358	12-11-80

PREPARED BY: W.S.

SYSTEM: A-Cup

MATERIAL: Shale Oil

SOURCE: Occ (Retort 6)

WEIGHT PER CENT SOLIDS — NOMINAL ____ % | ACTUAL ____ %

TEMPERATURES — BEFORE 110.3°F / 43.5°C | AFTER 110.1°F / 43.4°C

ADDITIVES: 0.05 gms of 5351 Nalco per 100 ml of Shale Oil

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				0.20 gms 5351 to 400 ml Shale Oil
2				at 80°F heated to 130°F to
3				mix good. This was done on
4	3.4	3.4	3.4	the 12-10-80
5	4.5	4.6	4.55	
6	6.5	6.7	6.6	
7	8.9	9.0	8.95	
8	11.7	11.9	11.80	
9	15.8	15.9	15.85	
10	20.9	21.0	20.95	
11	30.6	30.8	30.7	
12	41.6	41.8	41.7	
13	55.4	55.5	55.45	
14	75.1	75.3	75.2	
15	off scale		—	

DRY CUPS

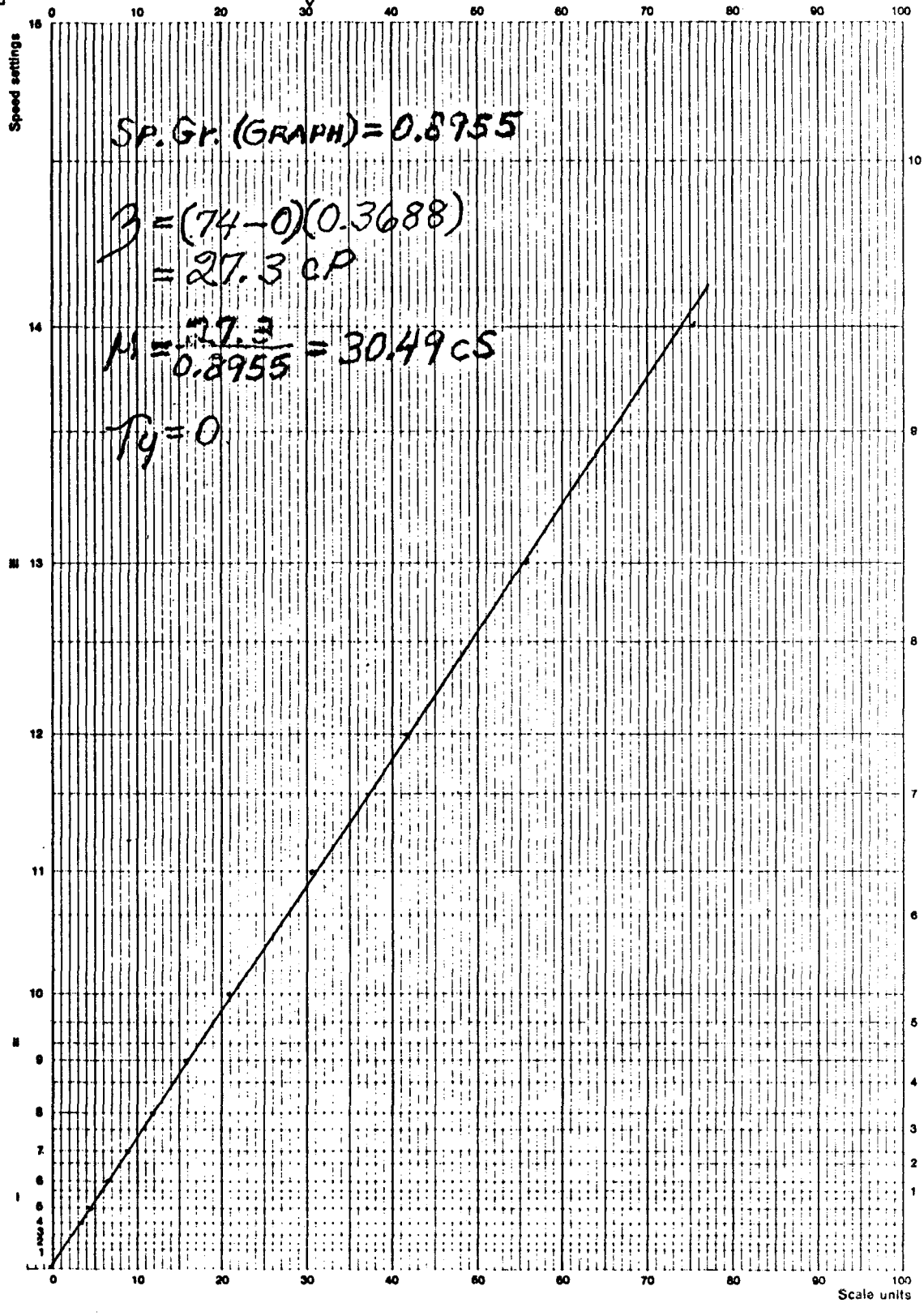
BEFORE		AFTER	
TIME PLACED IN OVEN:	☐AM ☐PM	TIME PLACED IN OVEN:	☐AM ☐PM
GROSS SLURRY WEIGHT	____ GMS	GROSS SLURRY WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SLURRY WEIGHT	____ GMS	NET SLURRY WEIGHT	____ GMS
GROSS SOLID WEIGHT	____ GMS	GROSS SOLID WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SOLID WEIGHT	____ GMS	NET SOLID WEIGHT	____ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT	____ × 100 = ____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	____ × 100 = ____ % WT.

LU-269

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	PH	NAME	DATE
OCCIDENTAL NALCO #5351 0.05 gms/100 ml	A-CUP 110.3°-110.1°F		HLP SHALE OIL, RT #6 55 GAL. DRUM	12/11/80



WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO.	DATE
4358	12-11-80

PREPARED BY: W.E.

SYSTEM: A-Cup

MATERIAL: Shale Oil

SOURCE: Oxy (Retort 6)

WEIGHT PER CENT SOLIDS — NOMINAL ____ % ACTUAL ____ %

TEMPERATURES — BEFORE 121.7°F / 55.4°C □F □C — AFTER 129.2°F / 54.0°C □F □C

ADDITIVES: 0.05 gm of 5351 Nalco per 100 ml of Shale Oil

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				0.20 gms of 5351 Nalco was added to 400 ml. of Shale oil 50°F taken from the 55 gal drum. It was heated to 130°F for mixing and then allowed to cool to room temp. This was done on the 12-10-80
2				
3				
4				
5				
6	4.1	4.2	4.15	
7	5.5	5.7	5.6	
8	7.4	7.6	7.5	
9	9.9	10.1	10.0	
10	13.3	13.5	13.4	
11	19.6	19.9	19.75	
12	26.7	27.0	26.85	
13	35.9	36.1	36.0	
14	48.9	49.1	49.0	
15	66.1		66.1	

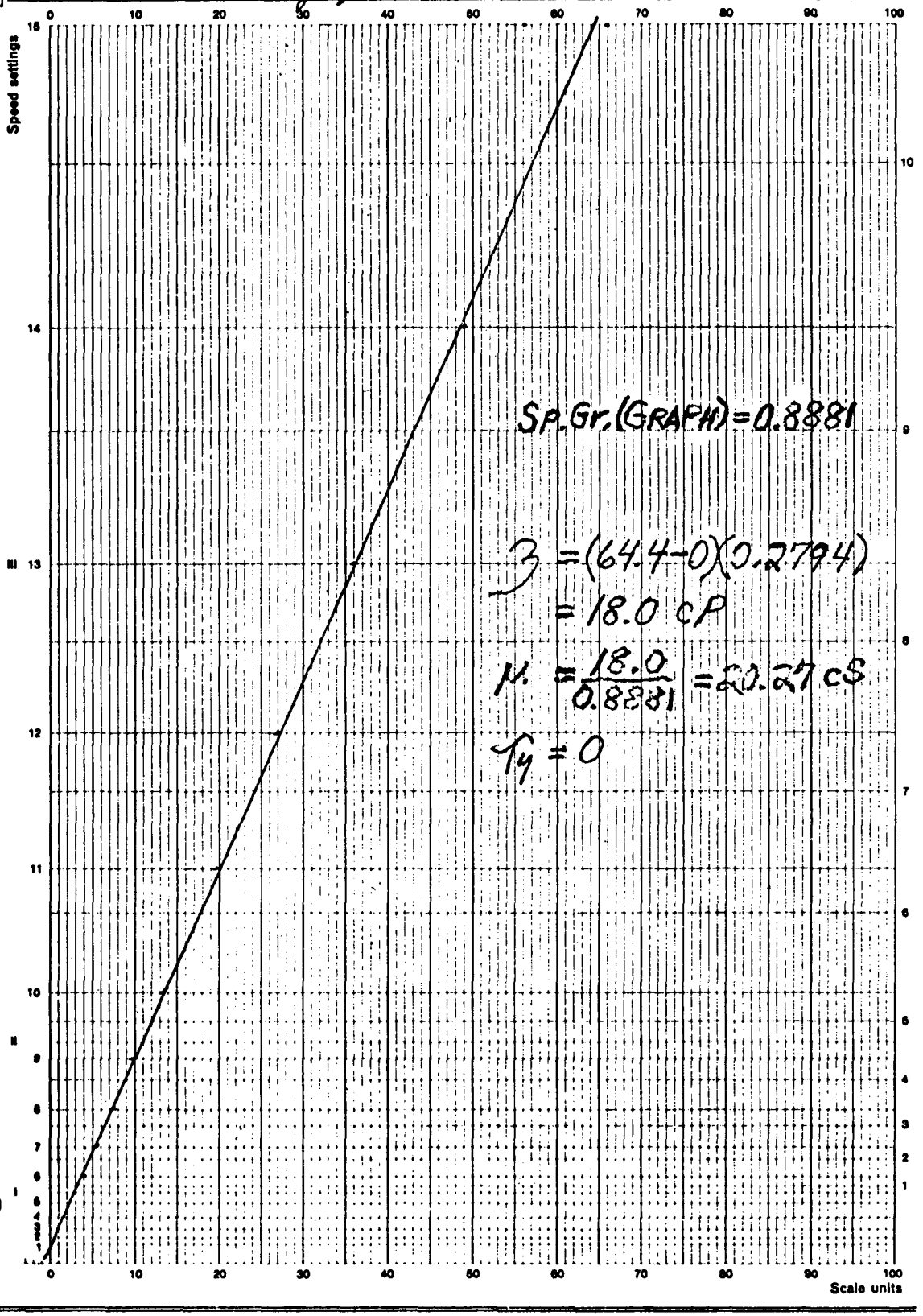
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN:	□AM □PM	TIME PLACED IN OVEN:	□AM □PM
GROSS SLURRY WEIGHT	____ GMS	GROSS SLURRY WEIGHT	____ GMS
LESS: CUP #____ TARE	____ GMS	LESS: CUP #____ TARE	____ GMS
NET SLURRY WEIGHT	____ GMS	NET SLURRY WEIGHT	____ GMS
GROSS SOLID WEIGHT	____ GMS	GROSS SOLID WEIGHT	____ GMS
LESS: CUP #____ TARE	____ GMS	LESS: CUP #____ TARE	____ GMS
NET SOLID WEIGHT	____ GMS	NET SOLID WEIGHT	____ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT	____ × 100 = ____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	____ × 100 = ____ % WT.

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	PH	NAME	DATE
OCCIDENTAL NALCO #5351 0.05 gms/100 ml	A-CUP		HLL	12/11/80
	131.7° - 129.2 °F		SHALE OIL, RT #6 55 GAL DRUM	



SLU-380

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4258 | DATE 12-11-80

PREPARED BY W.L.

SYSTEM A-Cup

MATERIAL Shale Oil

SOURCE Oxy (Retort 6)

WEIGHT PER CENT SOLIDS — NOMINAL ____ % | ACTUAL ____ %

TEMPERATURES — BEFORE 131.7°F 55.4° ☐F ☐C | AFTER 131.2°F 54.0° ☐F ☐C

ADDITIVES 0.05 gm @ 5351 Nalco per 100 ml of Shale Oil

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				0.20 gms @ 5351 Nalco was added to 400 ml @ 80°F oil taken from the 55 gal drum. It was heated to 130°F for mixing and then allowed to cool to room temp. This was done on the 12-10-80
2				
3				
4				
5				
6	4.1	4.2	4.15	
7	5.5	5.7	5.6	
8	7.4	7.6	7.5	
9	9.9	10.1	10.0	
10	13.3	13.5	13.4	
11	19.6	19.9	19.75	
12	26.7	27.0	26.85	
13	35.9	36.1	36.0	
14	48.9	49.1	49.0	
15	66.1		66.1	

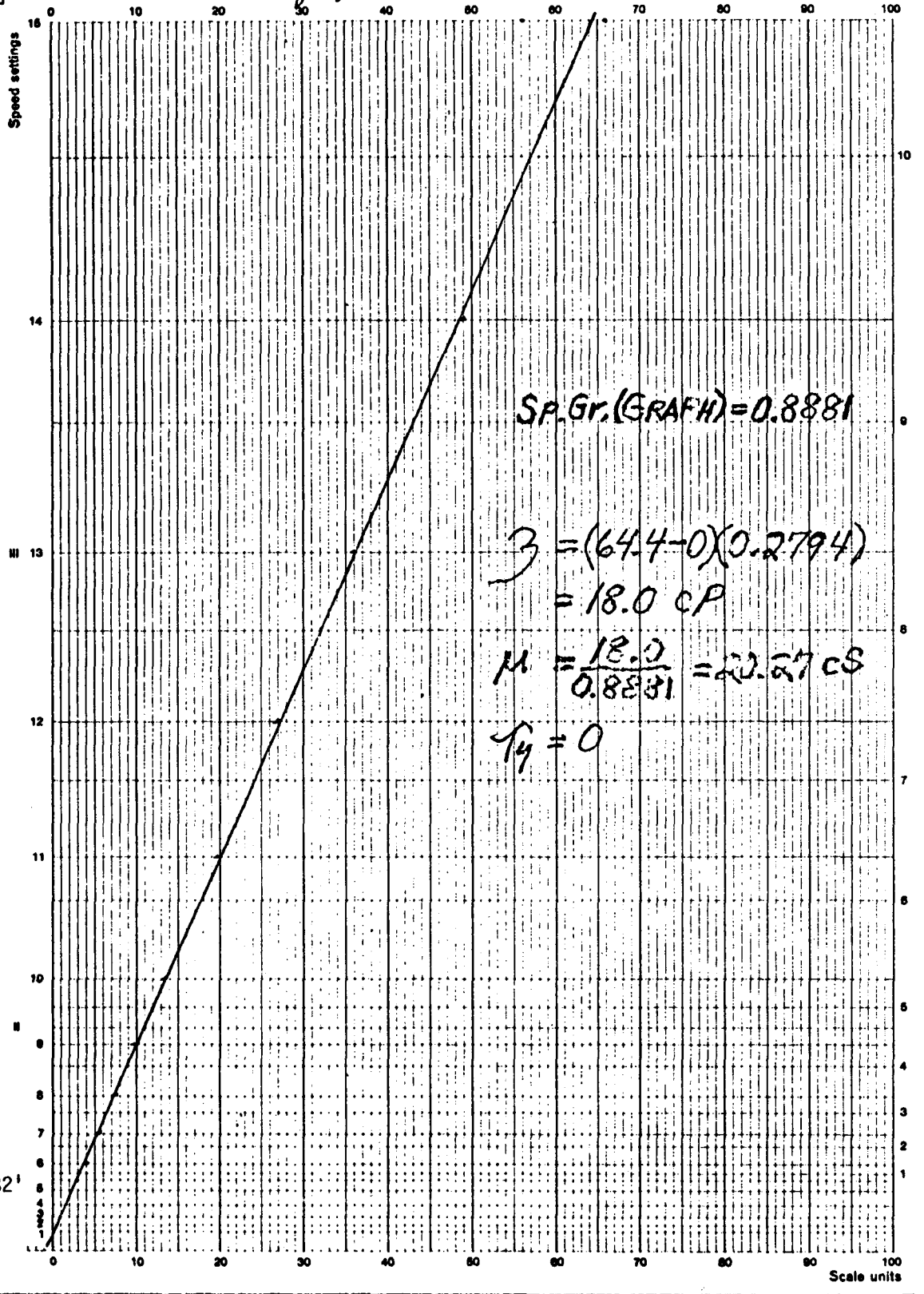
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	____ GMS	GROSS SLURRY WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SLURRY WEIGHT	____ GMS	NET SLURRY WEIGHT	____ GMS
GROSS SOLID WEIGHT	____ GMS	GROSS SOLID WEIGHT	____ GMS
LESS: CUP #___ TARE	____ GMS	LESS: CUP #___ TARE	____ GMS
NET SOLID WEIGHT	____ GMS	NET SOLID WEIGHT	____ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT ____ × 100 = ____ % WT.		NET SOLID WEIGHT / NET SLURRY WEIGHT ____ × 100 = ____ % WT.	

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	PH	NAME	DATE
OCCIDENTAL NALCO #5351 0.05 gms/100 ml	A-CUP		HLL	12/11/80
	131.7°-129.2°		SHALE OIL, RT #6 55 GAL DRUM	



582'

BLU-180

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 12-11-80

PREPARED BY W. C.

SYSTEM A-Cup

MATERIAL Shale Oil

SOURCE Retort-6 Oil

WEIGHT PER CENT SOLIDS — NOMINAL — % | ACTUAL — %

TEMPERATURES BEFORE 141.7°F / 65.5° ☐F ☐C | AFTER 141.7°F / 65.4° ☐F ☐C

ADDITIVES 0.05 gm of 535 Nalco per 100 ml. of Shale oil

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				0.20 gms of 535 was added to 400 ml. of Shale oil taken from the 55 gal. drum. It was heated to 130°F for mixing and allowed to cool to room temp. This was done on the 12-10-80
2				
3				
4				
5				
6				
7	3.8	3.7	3.75	
8	5.1	5.0	5.05	
9	6.8	6.7	6.75	
10	9.1	9.0	9.05	
11	13.5	13.4	13.45	
12	18.5	18.4	18.45	
13	24.8	24.7	24.75	
14	33.9	33.9	33.9	
15	45.9		45.9	

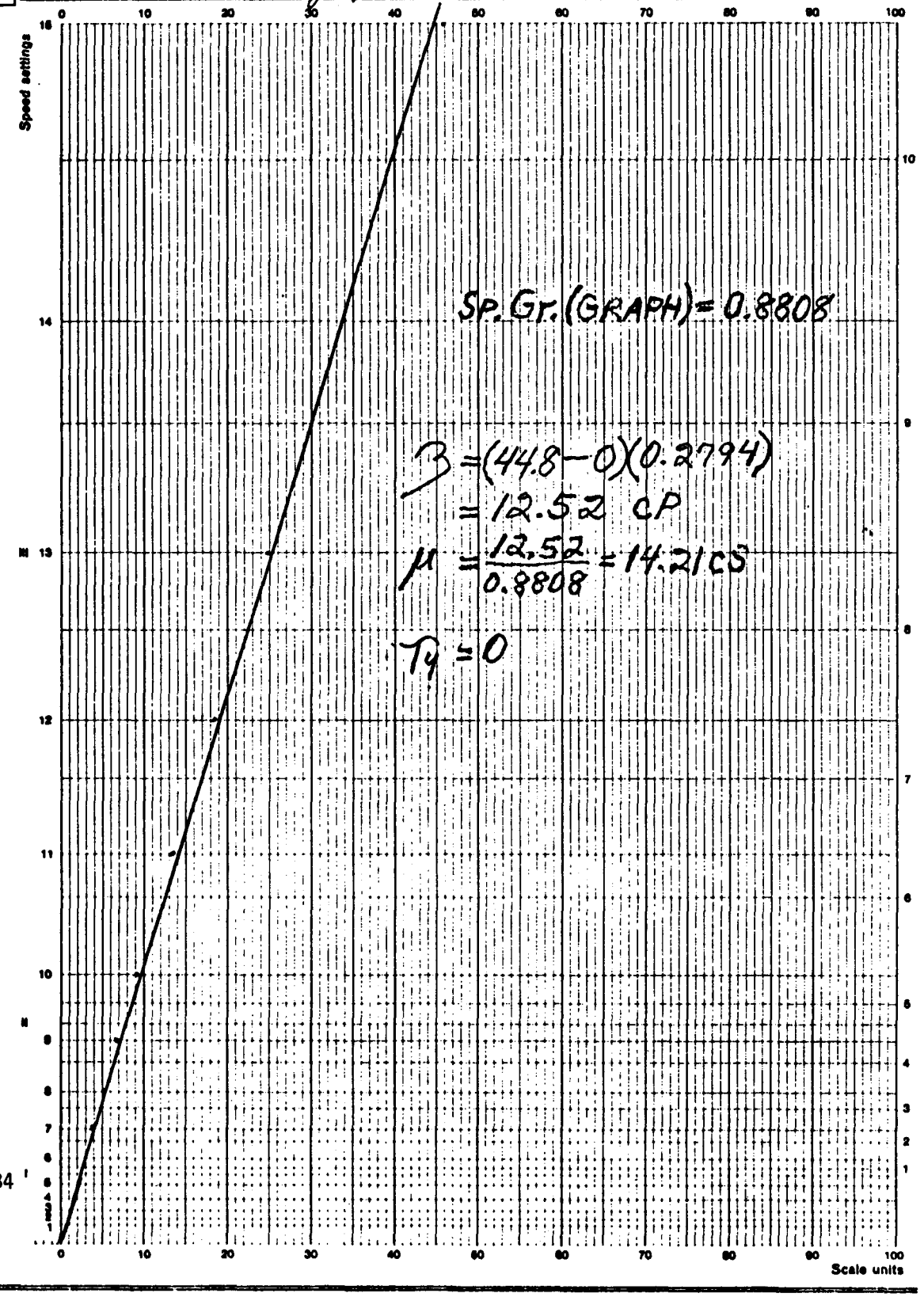
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	_____ GMS	GROSS SLURRY WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SLURRY WEIGHT	_____ GMS	NET SLURRY WEIGHT	_____ GMS
GROSS SOLID WEIGHT	_____ GMS	GROSS SOLID WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SOLID WEIGHT	_____ GMS	NET SOLID WEIGHT	_____ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	PH	NAME	DATE
OCCIDENTAL NALCO #5351	A-CUP		H22	12/11/80
0.05 gms/100ml	CONC. (% WT) 1499	TEMPERATURE (°F) 149.7	SHALE OIL, RT #6	55 GAL DRUM



584

SLU-380

WILLIAMS BROTHERS ENGINEERING COMPANY

VISCOSITY DATA – CONTRAVES

JOB NO. 4358 | DATE 12-11-80

PREPARED BY W. C.

SYSTEM A-Cup

MATERIAL Shale Oil

SOURCE Retort-6 Opg

WEIGHT PER CENT SOLIDS — NOMINAL — % | ACTUAL — %

TEMPERATURES BEFORE 141.9°F 65.5°C ☐F ☐C | AFTER 141.7°F 65.4°C ☐F ☐C

ADDITIVES 0.05 gm of 5351 Nalco per 100 ml. of Shale oil

SPEED SET	UP	DOWN	AVERAGE	REMARKS
1				0.20 gms of 5351 was added to 400 ml. of Shale oil taken from the 55 gal. drum. It was heated to 130°F for mixing and allowed to cool to room temp. This was done on the 12-10-80
2				
3				
4				
5				
6				
7	3.8	3.7	3.75	
8	5.1	5.0	5.05	
9	6.8	6.7	6.75	
10	9.1	9.0	9.05	
11	13.5	13.4	13.45	
12	18.5	18.4	18.45	
13	24.8	24.7	24.75	
14	33.9	33.9	33.9	
15	45.9		45.9	

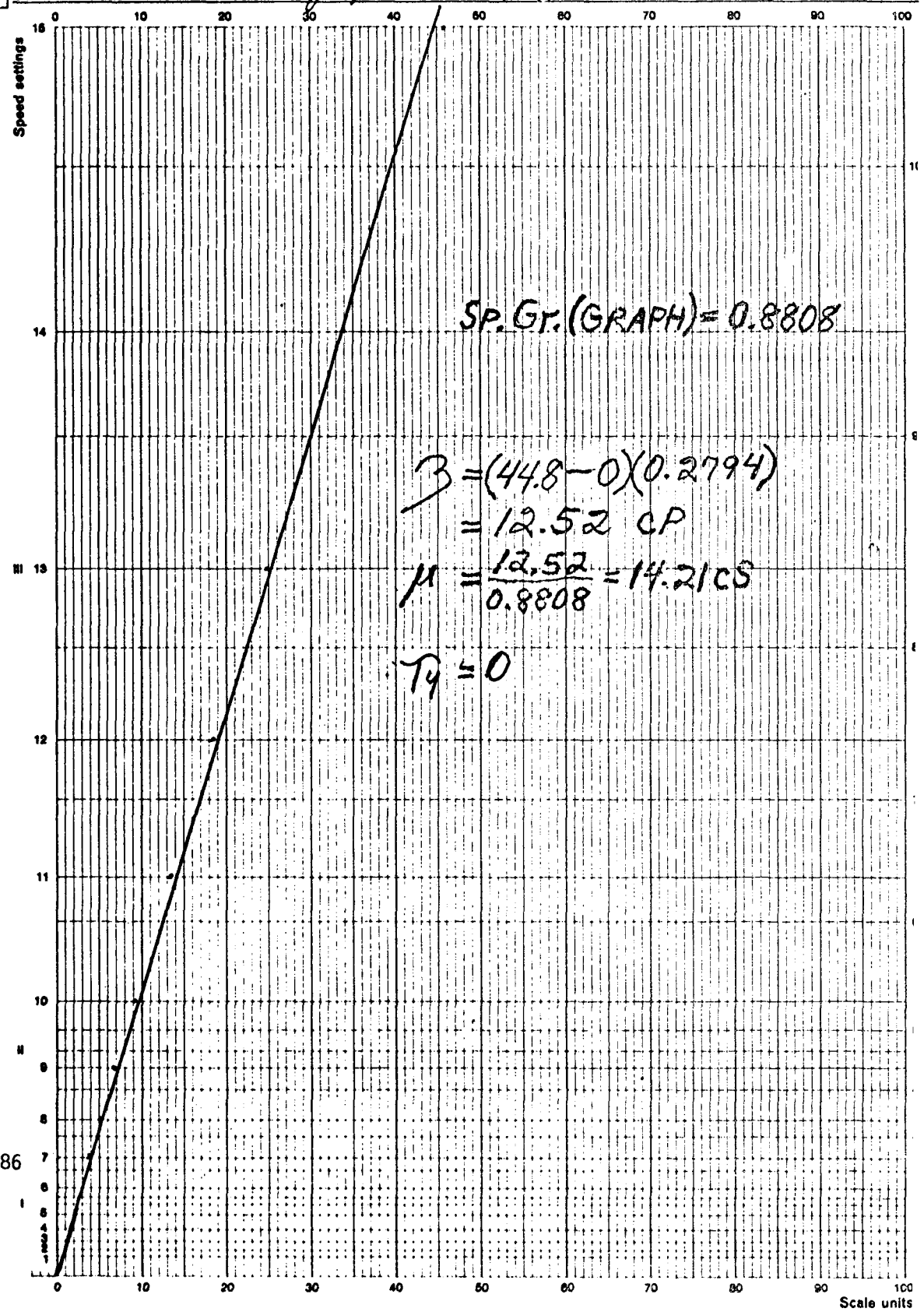
DRY CUPS

BEFORE		AFTER	
TIME PLACED IN OVEN: ☐AM ☐PM		TIME PLACED IN OVEN: ☐AM ☐PM	
GROSS SLURRY WEIGHT	_____ GMS	GROSS SLURRY WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SLURRY WEIGHT	_____ GMS	NET SLURRY WEIGHT	_____ GMS
GROSS SOLID WEIGHT	_____ GMS	GROSS SOLID WEIGHT	_____ GMS
LESS: CUP #___ TARE	_____ GMS	LESS: CUP #___ TARE	_____ GMS
NET SOLID WEIGHT	_____ GMS	NET SOLID WEIGHT	_____ GMS
NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.	NET SOLID WEIGHT / NET SLURRY WEIGHT	_____ × 100 = _____ % WT.

WILLIAMS BROTHERS ENGINEERING COMPANY

RHEOGRAM

RHEOGRAM NO.	SYSTEM	PH	NAME	DATE
OCCIDENTAL	A-CUP		H2O	12/11/80
NALCO #5351	CONCENTRATION	TEMPERATURE	SAMPLE OIL, RT #6	
0.05 gm/100ml	149.9°-149.7°F		55 GAL DRUM	



APPENDIX NO. 7

REFERENCE DATA ON

ADDITIVES BY SUPPLIERS

ARCO Chemical Company
Post Office Box 370
Sand Springs, Oklahoma 74063
Telephone 918-588-8293

Oil Field Chemicals

July 14, 1980

Mr. H. L. Lawler
Williams Brothers Engineering Company
6600 South Yale, Building #3
Tulsa, Oklahoma 74177

Dear Mr. Lawler:

Samples of the following paraffin control products were sent to your attention under separate cover for evaluation as flow improvers for shale oil in pipelines:

PRODUCT	FUNCTION
ArcoHib P-557	Inhibitor
ArcoHib P-560	Inhibitor
ArcoSol P-570	Dispersant
ArcoSol P-571	Dispersant
ArcoSol P-572	Solvent
ArcoSol P-575	Dispersant

In addition, a sample of experimental crude oil drag reducing additive designated #80-136 was included. As I explained, this product is not yet commercialized but several field tests have shown it to be effective in significantly reducing pressure drop and pumping requirements. It is shear sensitive so multiple injection points are necessary if several pump stations are involved. Concentrations up to 50 ppm have been effective. It can be diluted in kerosene for easier handling and pumping.

Product information bulletins on the P- series will be sent from our Plano, Texas, Marketing office. Someone from our Marketing group will be in touch with you at a later date. In the meantime, if you have any questions give me a call at 918/588-8377.

Yours very truly,

ARCO CHEMICAL COMPANY

Glenn D. Fielder

Glenn D. Fielder, Manager
Research and Development

JUL 1980
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Slurry Systems

GDF:bd

cc: G. F. Brock
J. M. Wagner

ARCO Chemical Company
Petroleum Industry Chemicals
Dallas, Texas 75221

PRODUCT BULLETIN

ArcoSol P-575 and P-576 Paraffin Dispersants

OUTSTANDING CHARACTERISTICS . . . . . Water soluble surfactants for paraffin removal.

DESCRIPTION

ArcoSol P-575 and P-576 contain a combination of detergents, dispersants and solvents effective in removing deposits of paraffin, oily solids and iron sulfide. ArcoSol P-576 is formulated for use in colder climates.

ArcoSol P-575 and P-576 are used downhole, in flow lines, free water knockouts, gun barrels, or any surface equipment where accumulations of paraffin and sludging deposits occur. They are used for tank bottom cleanup, for back washing filters, and to promote cleanup during well workover operations. ArcoSol P-575 and P-576 used with periodic circulation of pumping wells will help provide more consistent production volumes and in some cases has increased production.

ArcoSol P-575 and P-576 are water wetting compounds and as a result, deposition of paraffin may be prevented for some time in production strings and flow lines.

TYPICAL PHYSICAL PROPERTIES

	P-575	P-576
FORM	Light colored aqueous liquid	Same
DENSITY @ 60°F	8.47 lb/gal	7.90 lb/gal
POUR POINT	-5°F	-50°F
FLASH POINT (TCC)	94°F	74°F
pH	8-10	8-10
SOLUBILITY	Fresh water soluble Brine dispersible Oil dispersible	Same

APPLICATION METHODS

ArcoSol P-575 and P-576 are generally applied batchwise downhole by dumping a mixture of chemical and water down the annulus or in the case of gas lift wells, pumping down the tubing. Two to three gallons of ArcoSol P-575 and P-576 in each barrel of water is the recommended ratio for this treatment.

Flowline cleanup is usually accomplished by pumping a mixture of one or two gallons of ArcoSol P-575 or P-576 per barrel of water through the pipe. The most efficient and economical use of chemical is achieved by a combination of circulation and soaking. Hot water will shorten the time required and generally result in better overall cleanup.

A continuous feed of ArcoSol P-575 or P-576 to prevent deposition of paraffin and other solids in flowlines, treaters and stock tanks should be injected at a point which insures efficient mixing of chemical in the produced fluids such as at a valve, or pump suction. One or two gallons of chemical per 300 to 500 barrels of crude oil is a suggested ratio. For treating tank bottoms, two to three gallons per 500 barrels of crude should be thoroughly mixed by rolling the tank or using external circulation.

ARCO Chemical Company

Petroleum Industry Chemicals
PRC--Plano
Post Office Box 2819
Dallas, Texas 75221
Telephone 214 424 6547

PRODUCT BULLETIN

ArcoSol P-572 Paraffin Solvent

OUTSTANDING CHARACTERISTICS . . . . . Combination of highly effective solvents for paraffin removal.

DESCRIPTION

ArcoSol P-572 contains a combination of ingredients which are field proven broad spectrum paraffin solvents in the oil producing industry. ArcoSol P-572 removes paraffin deposits from downhole equipment such as tubing, pumps, and rods as well as production lines. Paraffin build-up in crude oil stock tanks and pipelines can be dispersed and removed by the use of ArcoSol P-572.

TYPICAL PHYSICAL PROPERTIES

FORM	Light colored liquid
DENSITY @ 60°F	7.03 lb/gal
POUR POINT	-50°F
FLASH POINT (TCC)	56°F
SOLUBILITY	Oil soluble Water insoluble

APPLICATION METHODS

Generally, ArcoSol P-572 is best applied by periodic batch treatment. In pumping wells, five or ten gallons poured into the tubing and left to soak overnight will often facilitate rod removal. Prior to pulling the well, however, ten gallons of diesel oil or kerosene should be poured into the tubing to reduce the fire hazard.

Flow lines are batch treated with lubricators near the well. Dosage and frequency of treatment vary widely according to the rate of oil production and severity of the problem. Pipelines and flow lines can quite often be kept free of paraffin by injecting ArcoSol P-572 while pigging the line.

SHIPPING AND HANDLING INSTRUCTIONS

ArcoSol P-572 is shipped in 55 gallon steel drums and in bulk as a Flammable Liquid, N.O.S.

A Material Safety Data Sheet outlining recommended safe handling of ArcoSol P-572 is available upon request.

The information in this bulletin is believed to be accurate, but all recommendations are made without warranty, since the conditions of use are beyond ARCO Chemical Company's control. The listed properties are illustrative only, and not product specifications. ARCO Chemical Company disclaims any liability in connection with the use of the information, and does not warrant against infringement by reason of the use of any of its products in combination with other materials or in any process.

ARCO Chemical Company
Petroleum Industry Chemicals
PRC - Plano
Post Office Box 2819
Dallas, Texas 75221
Telephone 214 424 8547

PRODUCT BULLETIN

ArcoSol P-571 Paraffin Dispersant

OUTSTANDING CHARACTERISTICS . . . . . Blend of oil soluble solvents and surfactants to remove and prevent paraffin deposition.

DESCRIPTION

ArcoSol P-571 is a blend of paraffin dispersants and solvents which can be used downhole to remove and control paraffin which causes plugging of pumps, tubing and flowlines. Accumulations of paraffin in free water knockouts and crude oil treating and storage equipment are greatly reduced. ArcoSol P-571 is effective in treating tank bottoms.

Because of the unique surfactants in ArcoSol P-571, paraffin remains dispersed in the oil phase which reduces paraffin problems in water handling facilities. In most cases, injection of ArcoSol P-571 with emulsion breakers will prevent paraffin and other solids from accumulating at the interface in knockouts and treaters resulting in more efficient operation and fewer upsets.

TYPICAL PHYSICAL PROPERTIES

FORM	Dark colored liquid
DENSITY @ 60°F	7.80 lb/gal
POUR POINT	-40°F
FLASH POINT (TCC)	107°F
SOLUBILITY	Fresh water and brine dispersible Oil dispersible

APPLICATION METHODS

Batch treatment without dilution is preferred for removing paraffin. Application of 10 to 20 gallons of ArcoSol P-571 down the tubing several hours before a well is pulled due to paraffin plugging will help in removal of the rod string. Flow lines can be cleaned of paraffin deposition with 5 to 15 gallons of P-571 for each 300 barrels of crude oil. In the treatment of tank bottoms, two or three gallons of P-571 for each 500 barrels of crude oil should be thoroughly mixed in the oil by rolling with gas or external circulation.

Downhole pumps, tubing, flowlines, heater treaters, and stock tanks can be kept clean of paraffin deposition by continuous application of ArcoSol P-571 with a chemical injection pump. A suggested treatment ratio for this type of application would be one or two gallons of ArcoSol P-571 to every 300-500 barrels of crude. Batch treatments can be used with adequate flush and circulation, particularly in low volume wells. The frequency of treatment and dosage depend on individual well characteristics.

Tank bottoms may be treated successfully by the addition of two to five gallons of ArcoSol P-571 for each 500 barrels of crude in the stock tank. The chemical should be mixed into the crude by rolling with a gas line or circulating through an external pump.

ARCO Chemical Company

Petroleum Industry Chemicals
PRC—Plano
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Telephone 214 424 8547

PRODUCT BULLETIN

ArcoSol P-570 Paraffin Solvent

OUTSTANDING CHARACTERISTICS . . . . . Paraffin solvent containing oil-soluble surfactant for paraffin dispersion.

DESCRIPTION

ArcoSol P-570 is a blend of paraffin dispersants and solvents. This product can be used downhole to remove and control paraffin which causes plugging of pumps, tubing and flowlines. Accumulations of paraffin in free water knockouts and crude oil treating and storage equipment are greatly reduced. ArcoSol P-570 is effective in treating tank bottoms.

Because of the unique surfactants in ArcoSol P-570, paraffin remains dispersed in the oil phase which reduces paraffin wet problems in water handling facilities. In most cases, injection of ArcoSol P-570 with emulsion breakers will prevent paraffin and other solids from accumulating at the interface in knockouts and treaters resulting in more efficient operation and fewer upsets.

TYPICAL PHYSICAL PROPERTIES

FORM	Dark colored liquid
DENSITY @ 60°F	7.83 lb/gal
POUR POINT	-25°F
FLASH POINT (TCC)	78°F
SOLUBILITY	Water dispersible Aromatic solvent soluble Aliphatic solvent dispersible

APPLICATION METHODS

Batch treatment is generally preferred, if removal of paraffin is desired. This method eliminates excessive dilution of the solvent by any crude present in the equipment. When wells are to be pulled because of paraffin plugging, an application of 5 to 15 gallons of ArcoSol P-570 down the tubing several hours before the stripping operation will greatly facilitate removal of the rod string.

Paraffin deposition in flow lines can be removed by treatment with 5 to 15 gallons of ArcoSol P-570 for each 300 barrels of crude. Application can be made by flowing a by-pass stream of crude through a pot containing the paraffin solvent.

Continuous feed of ArcoSol P-570 can be used to prevent paraffin deposition in flow lines, heater-treaters, and stock tanks. A suggested treatment ratio for this type of application would be one gallon to every 300 - 500 barrels of crude.

In the treatment of tank bottoms, ArcoSol P-570 can be added to the stock tank at a dosage of two to three gallons for each 500 barrels of crude. The crude should then be mixed either by rolling with a gas line or by circulating through an external pump.

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[illegible]
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ArcoHib P-560 (Continued)

The information in this bulletin is believed to be accurate, but all recommendations are made without warranty, since the conditions of use are beyond ARCO Chemical Company's control. The listed properties are illustrative only, and not product specifications. ARCO Chemical Company disclaims any liability in connection with the use of the information, and does not warrant against infringement by reason of the use of any of its products in combination with other materials or in any process.

ARCO Chemical Company

Petroleum Industry Chemicals
PRC—Plano
Post Office Box 2819
Dallas, Texas 75221
Telephone 214 424 8547

PRODUCT BULLETIN

ArcoHib P-560 Paraffin Control Product

OUTSTANDING CHARACTERISTICS. . . . . Combines inhibiting and solvent properties for total paraffin control.

DESCRIPTION

ArcoHib P-560 is a unique combination of highly effective paraffin solvents, used for the softening and removal of deposited paraffins, and organic inhibitors for the prevention of further deposition of paraffin from produced crude oils. This mixture of ingredients allows ArcoHib P-560 to be used for a complete paraffin treating program. The solvents in the product are used to disperse and remove deposits from downhole equipment such as tubing, pumps, and rods as well as production lines, crude oil stock tanks and pipelines.

The inhibitors work by "crystal distortion" to prevent the growth of paraffin crystals into heavy insoluble deposits. In this way, the paraffin remains "fluidized" in the crude oil and is, therefore, prevented from accumulating as a heavy sludge in tank bottoms, heater-treater interfaces, and on the walls of pipes of both surface and subsurface production equipment.

TYPICAL PHYSICAL PROPERTIES

FORM	Amber Liquid
DENSITY @ 60°F	7.66 - 7.78 lb/gal
DRUM WEIGHTS	421 - 428 lbs.
POUR POINT	-35°F
FLASH POINT	95° F
SOLUBILITY	Cil Soluble - Water Insoluble

APPLICATION METHODS

When ArcoHib P-560 is used to inhibit paraffin crystallization, continuous injection is recommended. It should be added to the crude oil ahead of the point where paraffin deposition is occurring. In most cases, this will require injection down the annulus. This will be possible if there are no annular fluids, or if those fluids consist primarily of oil. The severity of the problem will dictate dosage, but a typical rate would be one gallon of ArcoHib P-560 to 500 barrels of produced oil. An initial slug of 5 to 10 gallons should be made prior to continuous injection.

48 ppm by Vol.

Where continuous injection is not possible, ArcoHib P-560 is an effective paraffin solvent. In this usage, it should be applied by slug treatment once or twice a week. The procedure in this case should include pre-wetting the annulus with a barrel of produced fluid followed by a slug of 5 to 10 gallons of ArcoHib P-560 This should then be followed by circulation with an additional barrel or two of fluid.

ArcoHib P-560 can also be effective in treating tank bottoms where paraffin has separated out of stored crude oil. The bottoms should be circulated through a heater-treater or a hot-oil truck to redissolve the paraffin in the oil, while adding ArcoHib P-560 at a rate of two gallons to 500 barrels of oil. This will keep the paraffin in solution when the oil has cooled to ambient temperatures.

SHIPPING AND HANDLING INSTRUCTIONS

ArcoHib P-560 is shipped in 55 gallon steel drums and in bulk as a Flammable Liquid, N.O.S.

A Material Safety Data Sheet outlining recommended safe handling of ArcoHib P-560 is available upon request.

July 8, 1980

Mr. H. L. Lawler
Williams Brothers Engineering Co.
6600 South Yale, Building #3
Tulsa, Oklahoma 74177

Dear Mr. Lawler:

Being sent to you under separate cover are a number of samples which you requested. These samples include Visco 1111, Visco 915, Visco 958, Visco 4725, Visco 4750, Vi-Sep 301, Vi-Sep 103, and Vi-Sep 910. These products are surfactants, paraffin compounds, and emulsion breakers.

The Visco 1111 is a very effect non-ionic surfactant which is very effect in forming stable emulsions. Depending upon the properties of the crude in the water involved, we believe that you will find this product to be effective as an emulsifier at very low concentrations. May I suggest that you begin your testing at about 6 ppm.

The Visco 915, 958, 4725, and 4750 are all paraffin controlling compounds. All of these products work on the wax crystal modifications principles. These four are being sent to you so that you might find the one that is most effective against the particular crude with which you are working. The Visco 4725 also has very effective dispersant properties.

The Vi-Sep 103, 301, and 910 are emulsion breakers. These were selected because of their broad range and their effectiveness on surfactant caused emulsions. In your testing with these I would recommend starting at approximately 60 ppm. The amount of emulsion breaker necessary will be dependent upon the amount of the surfactant required and the severity of the emulsion which is formed. It is not inconceivable that much larger doses than

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the 60 parts will be required. Mr. Lawler, Nalco manufactures a broad line of emulsion breakers, and these were selected based upon the information which you gave me on the phone the other day. However, the ideal way to select an emulsion breaker is to evaluate the many products which we have on an emulsion to be treated. In this way, the best emulsion breaking program can be developed. If you find that these three are not effective, please let me know and we will make arrangements to help you develop an effective emulsion breaking program to resolve the emulsion formed in your project.

Thank you for calling Nalco with your chemical needs. We are looking forward to working with you in the future.

Best regards,

J. E. Mincy
Product Manager
Visco Chemicals

JEM:smm

TRETOLITE DIVISION
369 Marshall Avenue / Saint Louis, Missouri 63119
(314) 961-3500 / TWX 910-760-1660 / Telex 44-2417

July 8, 1980

H. L. Lawler
Williams Brothers Engineering Co.
6600 S. Yale
Building #3
Tulsa, OK 74177

Dear Sir:

Enclosed are some Tech Data Sheets covering TOL compounds sent to you under separate cover. Below is a summary of the related details of each formulations' usage.

CF-1	Crystal Modifier	SP $8.35/gal.	Usage 1000-5000 ppm
CF-3	Crystal Modifier	SP $4.30/gal.	Usage 1000-10,000 ppm
CF-8	Crystal Modifier	SP $5.75/gal.	Usage 500-5000 ppm
PD-46	Crystal Modifier/ Dispersant	SP $9.45/gal.	Usage 200-5000 ppm
T-61	Crystal Modifier	SP $5.10/gal.	Usage 500-2500 ppm
	Activation Temperature 150-200°F		
PD-57	Oil in Water Emulsifier	SP. $6.55/gal.	Usage 100-1000 ppm
XT-72	Oil in Water Emulsifier	SP. $9.55/gal.	Usage 100-500 ppm

If you have any questions please call.

Yours truly,

Mike

M. E. Newberry
Manager - Paraffin Control
314/961-3500, Ext. 383

MEN:jcb
Attach.

TRETOLITE DIVISION
369 Marshall Avenue / Saint Louis, Missouri 63119
(314) 961-3500 / TWX 910-760-1660 / Telex 44-2417

TOLAD-61

DESCRIPTION

TOLAD-61 is a completely organic, ash free heavy oil cold flow improver in an aromatic solvent. TOLAD-61 decreases the pour point of waxy gas oils, heavy gas oils, heavy fuel oils and topped crudes by modifying the wax crystal structure.

RECOMMENDED USE

TOLAD-61 is recommended to improve the cold flow properties of heavy gas oils and heavy fuel oils. Generally, TOLAD-61 has greatest activity in distilled products which have high wax content.

APPLICATIONS

TOLAD-61 will reduce the pour point of gas oils, heavy catalytic cracker feeds and distilled fuels by modifying the crystal structure to induce the formation of small isotropic crystals. A typical application of TOLAD-61 is pour point depression of a heavy catalytic cracker feed from a +75°F. natural pour to a +40°F. pour thereby allowing a refiner to pipe line the cat cracker feed from one refinery to another. TOLAD-61 will also reduce the pour point of #6 heavy distillate 40°F. to a sales specification of +55°F.

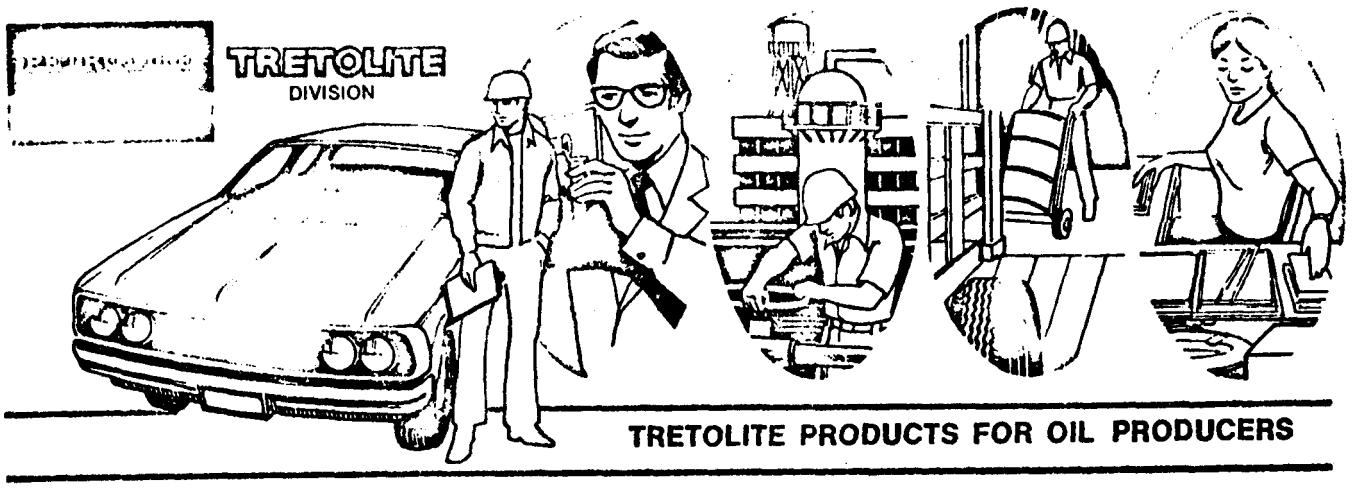
COMPATIBILITY

TOLAD-61 is compatible with all hydrocarbons and fuels particularly aromatic fuels. It is compatible with other cold flow improvers and fuel additives.

TYPICAL PHYSICAL PROPERTIES

Weight	7.1 lbs./gal. @ 130°F.
Flash Point (SFCC)	above 130°F.
Melt Point	100°F. - 105°F.
Viscosity	145 SUS @ 130°F. 70 SUS @ 212°F.
Ash	Nil

"The information contained in this technical bulletin is, to the best of our knowledge, true and accurate, but Petrolite Corporation disclaims any liability with respect to any recommendations or suggestions made in connection therewith. There are no warranties which extend beyond the description on the face hereof."



PARID® CF-1

CRYSTAL MODIFIER

Cold flow improver.
Viscosity reducer.

GENERAL DESCRIPTION. PARID CF–1 is a liquid, organic, oil-soluble chemical formulation for use in crude oil and distillate to control paraffin deposition and congealing oil due to paraffin crystals. It is a mixture of ester and amide derivatives of substituted polycarboxylic acids. It is not considered a toxic substance, but should be handled with the same precautions used for industrial solvents and surfactants.

RECOMMENDED USE. The flexibility and economics of crude oil production and transportation can be greatly improved by the use of CF–1 to achieve the desired cold weather crude oil handling properties. PARID CF–1 cold flow improver has been developed to provide better pumpability and reduced flow resistance for crude oils in production and pipeline operations where temperature changes would otherwise cause congealing, increased flow resistance and eventual plugging of flowlines and pipelines. An application of special importance is well-head injection to facilitate production of high pour point crude oils. With responsive crudes, effective pour point reductions of 20-60°F. have been observed.

APPLICATION. CF–1 can be added to crudes at any point in the crude oil production system, however, maximum efficiency is obtained when the addition is made to warm or hot crude oil. Wax crystals grow in crude oils as their temperature decreases. The addition of cold flow improver to cold crude oils may result in poor treating efficiency. Addition of CF–1 near the cloud point of the crude oil usually results in reduced efficiency. Continuous injection is more effective than batch treatment.

Concentrations in the order of 100-2000 ppm may be necessary for a significant reduction in congealing temperature. Lower concentrations are usually adequate for the inhibition of paraffin deposition or treatment of troublesome tank bottom accumulations.

HANDLING. CF–1 contains aromatic solvent and should therefore not be allowed to remain in contact with skin nor should contaminated clothing be worn for a prolonged period of time. Eyes should be protected. In case of accidental splashing on the skin wash with soap and water.

TYPICAL PHYSICAL PROPERTIES.

Specific Gravity at 60°F.	.883
Flash point °F., SFCC	110
Pour point °F.	+25
Viscosity @ 0°	---
Viscosity @ 30°	76.3
Viscosity @ 60°	52.1
Ash	Nil

AVAILABILITY. CF–1 is available in 55 gallon drums and in bulk quantities. You can get Parid CF–1 quickly and easily from any of the conveniently located Tretolite distribution center or field stocks.

600

TRETOLITE DIVISION

PARID Paraffin Dispersant
PD-46

Description:

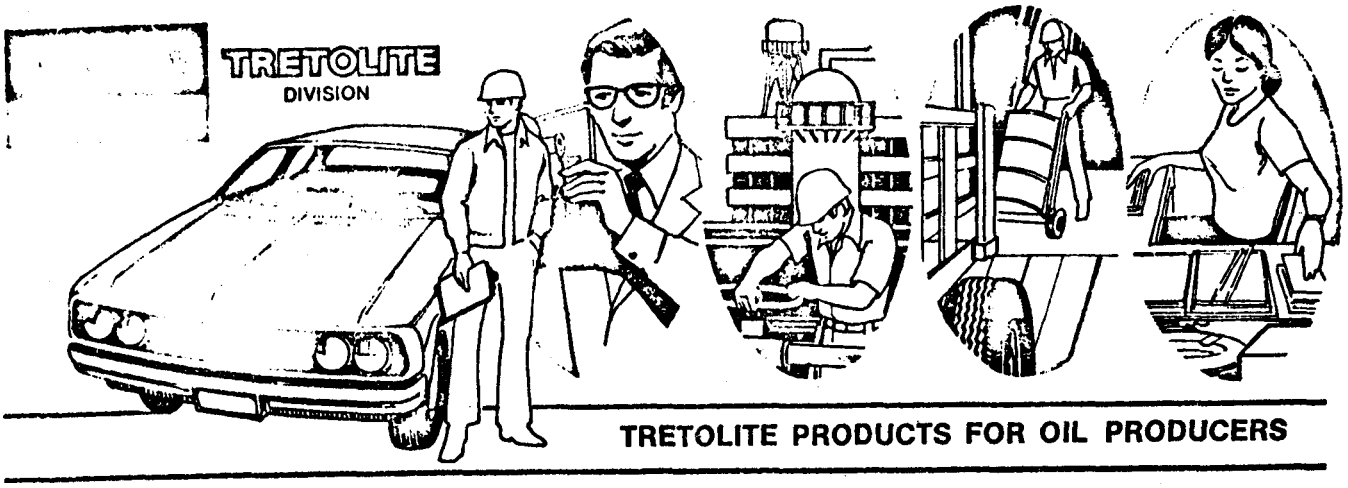
PARiD Paraffin Dispersant PD-46 is a liquid, organic, oil soluble, chemical for use in crude oil and distillate to control paraffin deposition and congealing problems due to paraffin crystallization. PD-46 is a nitrogenous derivitive of substituted carboxylic acids.

Application:

PD-46 is most effectively added to the system ahead of the point where paraffin has started precipitating. When present in the fluid along with the paraffin in solution, it acts by a crystal distortion mechanism to prevent the paraffin from forming normal crystals. Concentrations in the order of 200 to 4000 ppm may be required for a significant reduction in congealing temperature. Lower concentrations are usually adequate for paraffin deposition control. PD-46 is primarily considered a preventive agent but in some systems, gradual removal of already existing paraffin deposits have been observed following introduction of PD-46.

Typical Physical Properties:

Specific Gravity, 60° F.	.8824
Flash Point, °F. SFCC	105
Pour Point, ° F.	-8
Viscosity, 100° F. SUS	41
Viscosity, 130° F. SUS	38



PARID® CF-8

CRYSTAL MODIFIER

Cold flow improver.
Viscosity reducer.

GENERAL DESCRIPTION. PARID CF–8 is a liquid, organic, oil-soluble chemical formulation for use in crude oil and distillate to control paraffin deposition and congealing oil due to paraffin crystals. It is a mixture of ester and amide derivatives of substituted polycarboxylic acids. It is not considered a toxic substance, but should be handled with the same precautions used for industrial solvents and surfactants.

RECOMMENDED USE. The flexibility and economics of crude oil production and transportation can be greatly improved by the use of CF–8 to achieve the desired cold weather crude oil handling properties. PARID CF–8 cold flow improver has been developed to provide better pumpability and reduced flow resistance for crude oils in production and pipeline operations where temperature changes would otherwise cause congealing, increased flow resistance and eventual plugging of flowlines and pipelines. An application of special importance is well-head injection to facilitate production of high pour point crude oils. With responsive crudes, effective pour point reductions of 20-60°F. have been observed.

APPLICATION. CF–8 can be added to crudes at any point in the crude oil production system, however, maximum efficiency is obtained when the addition is made to warm or hot crude oil. Wax crystals grow in crude oils as their temperature decreases. The addition of cold flow improver to cold crude oils may result in poor treating efficiency. Addition of CF–8 near the cloud point of the crude oil usually results in reduced efficiency. Continuous injection is more effective than batch treatment.

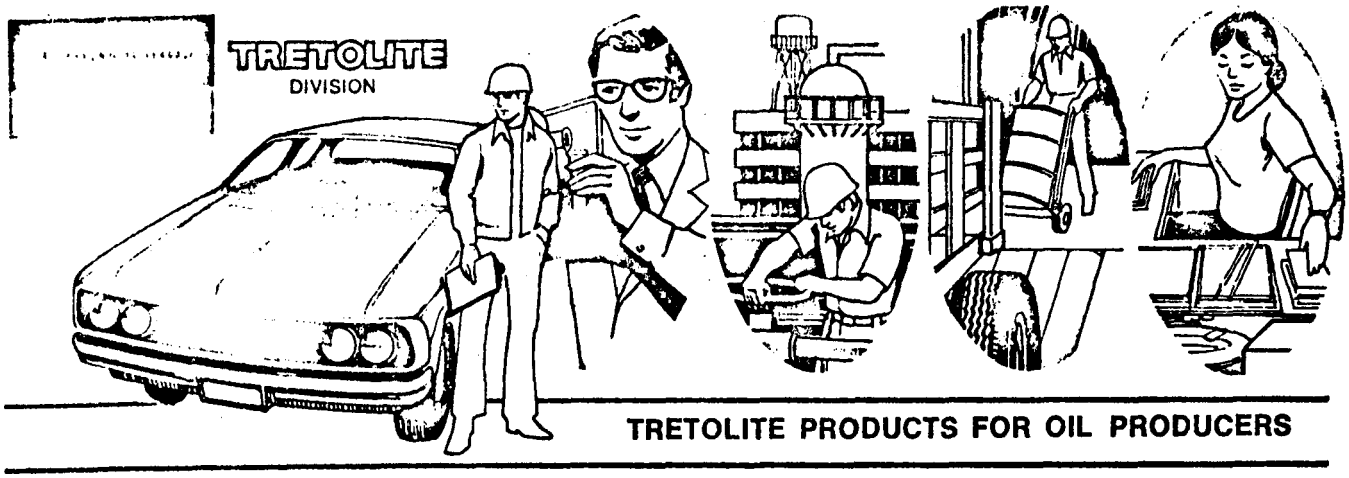
Concentrations in the order of 100-2000 ppm may be necessary for a significant reduction in congealing temperature. Lower concentrations are usually adequate for the inhibition of paraffin deposition or treatment of troublesome tank bottom accumulations.

HANDLING. CF–8 contains aromatic solvent and should therefore not be allowed to remain in contact with skin nor should contaminated clothing be worn for a prolonged period of time. Eyes should be protected. In case of accidental splashing on the skin wash with soap and water.

TYPICAL PHYSICAL PROPERTIES.

Specific Gravity at 60°F.	.891
Flash point °F., SFCC	95
Pour point °F.	+30
Viscosity @ 0°	---
Viscosity @ 30°	---
Viscosity @ 60°	69
Ash	Nil

AVAILABILITY. CF–8 is available in 55 gallon drums and in bulk quantities. You can get Parid CF–8 quickly and easily from any of the conveniently located Tretolite distribution center or field stocks.



PARID® CF-3
CRYSTAL MODIFIER

Cold flow improver.
Viscosity reducer.

GENERAL DESCRIPTION. PARID CF–3 is a liquid, organic, oil-soluble chemical formulation for use in crude oil and distillate to control paraffin deposition and congealing oil due to paraffin crystals. It is a mixture of ester and amide derivatives of substituted polycarboxylic acids. It is not considered a toxic substance, but should be handled with the same precautions used for industrial solvents and surfactants.

RECOMMENDED USE. The flexibility and economics of crude oil production and transportation can be greatly improved by the use of CF–3 to achieve the desired cold weather crude oil handling properties. PARID CF–3 cold flow improver has been developed to provide better pumpability and reduced flow resistance for crude oils in production and pipeline operations where temperature changes would otherwise cause congealing, increased flow resistance and eventual plugging of flowlines and pipelines. An application of special importance is well-head injection to facilitate production of high pour point crude oils. With responsive crudes, effective pour point reductions of 20-60°F. have been observed.

APPLICATION. CF–3 can be added to crudes at any point in the crude oil production system, however, maximum efficiency is obtained when the addition is made to warm or hot crude oil. Wax crystals grow in crude oils as their temperature decreases. The addition of cold flow improver to cold crude oils may result in poor treating efficiency. Addition of CF–3 near the cloud point of the crude oil usually results in reduced efficiency. Continuous injection is more effective than batch treatment.

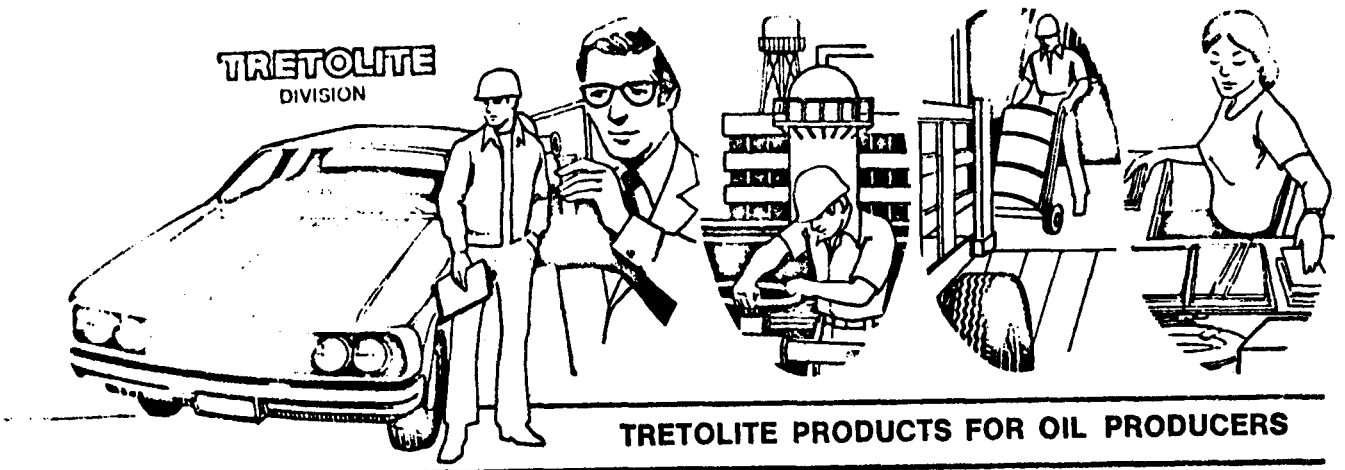
Concentrations in the order of 100-2000 ppm may be necessary for a significant reduction in congealing temperature. Lower concentrations are usually adequate for the inhibition of paraffin deposition or treatment of troublesome tank bottom accumulations.

HANDLING. CF–3 contains aromatic solvent and should therefore not be allowed to remain in contact with skin nor should contaminated clothing be worn for a prolonged period of time. Eyes should be protected. In case of accidental splashing on the skin wash with soap and water.

TYPICAL PHYSICAL PROPERTIES.

Specific Gravity at 60°F.	.878
Flash point °F., SFCC	101
Pour point °F.	+55
Viscosity @ 0°F.	---
Viscosity @ 30°F.	---
Viscosity @ 60°F.	58
Ash	Nil

AVAILABILITY. CF–3 is available in 55 gallon drums and in bulk quantities. You can get Parid CF–3 quickly and easily from any of the conveniently located Tretolite distribution center or field stocks.



PARID® PD-57
DISPERSANT

Controls paraffin deposition. Facilitates the production of high viscosity crude oils.

PARID PD–57 is a liquid, organic, surface active chemical for use in crude oil to control paraffin deposition and to assist in the production of viscous crude oils. This water soluble formulation is effective in removing and preventing paraffin in or on production equipment. PD–57 is also an excellent chemical to facilitate the production of high viscosity crudes, typically low gravity asphaltic types. PD–57 lowers the viscosity and thus reduces the production costs associated with these crudes because of the extremely high heating and lifting expenses.

By batch treatment or injection PD–57 removes accumulated paraffin or acts as a preventive. It removes accumulated paraffin deposits through detergent action. It also prevents deposits by keeping the paraffin particles dispersed and non-sticky. By lowering the viscosity of troublesome crude oils, PD–57 reduces high production expenses caused by excessive heating, lifting, and pumping costs. By utilizing water either produced or supplemented, the PD–57 will disperse or emulsify the crude into water for transportation from down hole to the treating facility.

A typical batch treatment for paraffin removal would consist of 5 to 10 gallons of PD–57 down the annulus at one- to four-week intervals, depending on the severity of the problem. The chemical may be mixed with hydrocarbons, well fluids or water. It can be added straight and flushed down with a slug of fluid or by circulating the well. Experience will dictate the optimum quantity of chemical and frequency of treatment. It is strongly recommended that, for maximum effectiveness, treatments be programmed on a regular periodic basis.

A typical program of continuous injection would consist of adding 200-500 ppm PD–57 until the system is clean and then reducing to some lower concentration to keep it clean (usually 50 to 100 ppm is adequate).

To facilitate lifting and movement of viscous crude oils PD–57 is usually injected downhole with a water flush. The amount of PD–57 will range between 200-1000 ppm. The amount of water required for movement of oil downhole or in surface lines varies between 10 and 20% minimum depending on the crude type. Lab tests can be run to determine the amount of water needed. If produced water found in the crude is not of sufficient volume, additional water can be added with the flush.

The handling of PD–57 should create no problems. When contacted PD–57 should be washed with plenty of water. As with any industrial surfactant, due care should be exercised.

Physical Properties

Specific Gravity	1.077
Pour Point °F	15
Flash Point °F SFCC	Above 200
Viscosity at 100°F SUS	2,020
Solubility	Water

EXXON CHEMICAL COMPANY U.S.A.

8230 Stedman Street, Houston, Texas 77029

SPECIALTIES DEPARTMENT
OIL FIELD CHEMICALS

EXXON CHEMICALS

August 18, 1980

Mr. H. L. Lawler
WILLIAMS BROTHERS
6600 S. Yale Ave., Bldg. 3
Tulsa, OK 74177

Dear Mr. Lawler:

We are sending you 8-ounce samples of the following chemicals for use in your work to develop a system for transporting shale oil as a water external phase emulsion.

Product	Description	Remarks
COREXIT 7826	Wax Crystal Modifier	Act as pour point depressants
COREXIT 7831	Wax Crystal Modifier	test from approximately 1000 ppm
COREXIT 7833	Wax Crystal Modifier	Downward
COREXIT 8596	Emulsifying Agent	Catonic
COREXIT 8587	Nonionic Surfactant	Possible emulsifier
BREAXIT 7926	Reverse Demulsifier	Test in 15 to 500 ppm range
BREAXIT 8014	Reverse Demulsifier	for resolving water external
BREAXOT 8015	Reverse Demulsifier	phase emulsion with shale
BREAXIT 8034	Reverse Demulsifier	oil.
BREAXIT 8044	Reverse Demulsifier	
BREAXIT 8120	Reverse Demulsifer	

I trust that some of these products will be of continuing interest. I will call you for an appointment for a visit the next time I am in Tulsa. In the meantime, please do not hesitate to call me if we can assist you in any way. In my absence feel free to call Ken Becker of our Technology Department at Phone (713) 671-8621.

Thank you for your interest in our products.

Very truly yours,

Carl Wilkinson/ds

C. T. Wilkinson

CTW:ds

cc: K. W. Becker
T. L. Gray

AUG 1980
RECEIVED
Slurry Systems

Res.: Tulsa 918-[redacted]
587-1[illegible]

Lab Chemist - Supvr
Bill Campbell
Bill Hoover

Steven L. Braselton

Witco Chemical Corporation
3230 Brookfield Street
Houston, Texas 77045

presentative
rganics Division

July 17, 1980

Mr. H. L. Lawler
Williams Brothers Engineering
6600 S. Yale Ave.
Tulsa, OK 74177

Dear Mr. Lawler:

Thank you very much for your interest in Witco products. Samples for the uses that you discussed have been requested for you as follows:

Experimental 4906-27A
Experimental 4906-27B

These are for your evaluation as wax crystal modifiers or pour point depressants.

Samples of Emcol D51-51 and Emcol D51-52 are emulsifiers for water in oil emulsions and should serve to emulsify crude oil.

Called for Lane on 7/25 Out Int[illegible] Ma[illegible]

If you need any additional information or samples, please feel free to call on us.

We appreciate the opportunity of working with you on this project.

Sincerely yours,

WITCO

Richard N. Lane
Product Manager/
Oilfield Surfactants

I called Lane on 7/24/80 about water in oil emulsions. He then made right at 1/4 hr. Will write letter when back and never later. Also will send some demulsifiers.

JUL 1980
RECEIVED
Slurry Systems

cc: Mr. Steve Braselton, Witco, Tulsa

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The information presented herein is based on the best data available and is believed to be correct. However, nothing stated in this letter is to be taken as a warranty, expressed or implied regarding the accuracy of the information or the use of our product; nor shall anything contained herein be construed to constitute a permission or recommendation to practice any invention covered by a patent or patent application, or know how owned by WITCO CHEMICAL CORPORATION, any of its divisions, or by others, without a license from the owner of the patent, patent application or know how.

P 45 PARAFFIN INHIBITORS

OUTSTANDING CHARACTERISTICS.....Prevents or inhibits paraffin deposition at a dosage of 3 - 12 ppm.

DESCRIPTION

Pro-Finer Paraffin Inhibitors are a blend of oil soluble and water soluble deumulsifiers bridged with oil soluble and water soluble wetting agents and dispersants.

These Inhibitors are a relatively new development designed to prevent or inhibit the growth and agglomeration of waxy particles and to keep these small particles suspended in the crude oil. Thus, the paraffin particles are "fluidized" and prevented from accummulating on pipe walls as insoluble deposits, thereby reducing pigging and pumping requirements, downtime, and loss of throughput volume. Heavy sludge deposits in stock tank bottoms can also be diminished, thereby increasing the amount of pipeline quality crude oil and reducing the loss of tank storage capacity.

In addition, Pro-Finer Paraffin Inhibitors aid in the desalting process at the refinery by eliminating waxy tank bottoms and paraffin slugs to the desalter. They have been in use for about seven years and no adverse effects on desalting have been reported. These Inhibitors contain no ingredients harmful to pipeline or refinery operations or to refinery products.

TYPICAL PHYSICAL PROPERTIES

FORM	Dark Amber Liquid
DENSITY @ 60°F (lb/gal)	7.75 to 7.90
FLASH POINT	Below 77
POUR POINT, °F	-15

Contains no arsenic, heavy metals, or organic chlorine compounds.

APPLICATION METHODS

Pro-Finer Paraffin Inhibitors are best applied by continuous injection into a clean flow, gathering or main pipeline system. Dosage can vary widely depending upon the type of crude oil, rate of throughput and prevailing thermal conditions for a given area.

While batch treating has met with some success in the Oklahoma-Kansas area, this method of treating does not allow Pro-Finer Paraffin Inhibitors to perform as effectively and economically as when it is injected continuously at or near the source of the pipeline crude oil. Batch treating for the dispersal of heavy paraffin bottoms in onshore storage tanks has proven to be successful in the Oklahoma-Kansas area. Heavy paraffin bottoms as deep as 8 feet have been removed as saleable crude oil from offshore tank barges in the Louisiana area. In general, the dosage of paraffin inhibitor used to "fluidize" such heavy tank bottoms has been in the range of 5 to 10 gallons per 1,000 barrels of bottoms.

HANDLING PRECAUTIONS

These Paraffin Inhibitors are considered to be flammable according to recent ICC regulations. Care should be exercised to prevent vapor exposure to sparks or flames. Store in a ventiliated area away from engines, electric motors, and open flame.

Pro-Finer Paraffin Inhibitors are non-toxic. As is the case with most chemicals, exposures should be kept to a minimum to avoid irritation. Wash exposures with soap and water.

Chemical Compounds Corporation for the Petroleum Industry

P-041 PARAFFIN SOLVENT

OUTSTANDING CHARACTERISTICS.....Fast penetration to soften and loosen hard paraffin deposits from pipewalls.

DESCRIPTION

Pro-Finer P-041 Paraffin Solvent is a blend of aromatic and other solvents and is a significant improvement and over earlier products of this type. It is designed to aid in the removal of paraffin deposits by penetrating and softening the deposit quickly so they may be flushed or pushed out of the pipeline. P-041 solvent is noncorrosive and does not contain carbon bisulfide or any chemical that may be harmful to refinery process equipment.

TYPICAL PHYSICAL PROPERTIES

FORM	Clear Liquid
DENSITY	7.02 lbs/gal
POUR POINT	-20°F
FLASH POINT	Below 80°F
SOLUBILITY	Oil Soluble Water Insoluble

APPLICATION METHODS

Pro-Finer P-041 Solvent works best if applied full strength into the pipeline.

Excellent results are obtained when P-041 is included in a regular scraping maintenance program. By batch treating 10 to 15 gallons of P-041 through a scraper trap, paraffin deposits are softened and loosened ahead of the scraper to reduce the possibility of a line rupture due to hard paraffin deposits and excessive scraper pressure.

A low spot in a line restricted by paraffin can be cleaned by moving 1/2 to 1 drum of P-041 solvent to the restricted area, allow the solvent to soak for 24 hours, then flush the softened deposit out with crude oil or push the deposit out with a scraper.

Once the pipeline is clean, continuous injection of a Pro-Finer Paraffin Inhibitor/Dispersant at a low dosage will help to keep the line clean by keeping the paraffin particles suspended in the oil. Thus, the paraffin is fluidized and prevented from accumulating on pipewalls as insoluble deposits.

Pro-Finer P-041 Solvent can also be used to clean crude oil, paraffin, dirt and rust from meters and other pipeline equipment where painted surfaces are not a concern. P-041 solvent will soften some paints. If splashed on a car or truck, wash off immediately to avoid damage to the paint finish.

HANDLING PRECAUTIONS

Due to the solvent mixtures of P-041, avoid excessive inhalation of vapors. Avoid eye contact, safety goggles should be worn as a precaution. If exposed to skin, wash thoroughly with soap and water. Clothing should be immediately removed and thoroughly washed before wearing again.

Pro-Finer P-041 Solvent is considered flammable, store and use in well ventilated areas, away from sparks or open flames.

A PRO-FINER CASE HISTORY CLEANING CRUDE PIPELINES WITH A WATER "PIG"

12.5 miles of crude pipeline - 6" to double 4" to 6" was successfully cleaned with controlled emulsification and demulsification of fresh (potable) water and our Pipeline Paraffin Inhibitor P-45 in a 5% solution.

Our water "pig", 1/2 mile long, was injected from a tank truck after mixing 5% P-45 in the water. The water was injected under no flow conditions into the 6" crude line. Pipeline pumps were started and the water "pig" was packed in turbulent flow with the regualr crude delivery to the terminal.

At the terminal a clean 500 Bbl. tank caught the water "pig" for evaluation. All water was recovered along with 1-1/2 Bbl. of paraffin, 1/2 Bbl. of dirt and rust, and 540# of salt as NaCl by titration. No mechanical pigs were used.

Crude pipelines of any length, size or multiple sizes can be cleaned with a water "pig".

Since it is difficult to inhibit a crude pipeline with a corrosion inhibitor due to the accumulation of paraffin, dirt, and salt crystals on pipe interior walls, it is possible to incorporate a corrosion inhibitor in the water "pig" formula if a corrosion control program is to be initiated after cleaning the line.

Laboratory tests on the crude are conducted prior to making a recommendation for the Pipeline Paraffin Inhibitor to be used in the water "pig". Several inhibitors are available - all with varying degrees of activity regarding emulsification and demulsification of the water and crude oil.

APPENDIX NO. 8

OCCIDENTIAL SHALE OIL

TEST AND REFERENCE DATA ON

SHALE OILS PREPARED BY

OCCIDENTAL OIL SHALE, INC.

GRAND JUNCTION, COLORADO

W. Lawler

OCCIDENTAL OIL SHALE, INC.

P. O. BOX 2687 2372 G ROAD GRAND JUNCTION, COLORADO 81501
(303) 242-8463

August 5, 1980

Williams Brothers Engineering Company
Research Center
6600 S. Yale
Tulsa, Oklahoma 74177

Dear Mr. Tennant:

Attached is the analysis for oil from the same barrel as your sample. The previous analysis was average properties for similar barrels as that particular barrel had not yet been analyzed.

Should you have any questions on this oil, please feel free to call me.

Yours very truly,

OCCIDENTAL OIL SHALE, INC.

Robert A. Atwood
Chemist

RAA:cmh

AUG 1980
RECEIVED
Slurry Systems

RETORT 6 OIL ANALYSES

TEST	REFERENCE	SAMPLE		
		RT-6 VIA ANVIL POINTS	RT-6 ARITH-METIC AVERAGES	RT-6 COMPOSITE SAMPLE
% BS&W	ASTM-D-96-23	0.4	.15	<.05
API Gravity 60°	ASTM-D-1298-23	23.2	23.6	23.7
API @ 100°F = 24.6	Sp. Gr =	0.9147 @ 60°F 0.9042 @ 100°F		
Pour Point °F	ASTM-D-97-23	55	50	35
Kinematic Viscosity	ASTM-D-445-23			
@ 100°F CST	cP = 34.13	37.75	31.35	30.40
@ 140°F CST		14.18	12.77	12.53
Cleveland Open Cup	ASTM-D-92-23			
Flash °F		290	240	260
Fire °F		315	260	275
Pensky Martin Flash Point °F	ASTM-D-93-23	262	217	222
% Sulfur	ASTM-D-129-23	.75	.62	.82
Heating Value BTU/lb	ASTM-D-240-23	19,000	18,800	18,800
% Asphaltene	UOP-614-68	.34	.33	.52
% Nitrogen	ASTM-D-3228-25	1.38	1.35	1.34
Arsenic, ppm	UOP-837-62	18	16	16

APPENDIX H

Pace Marketing Report

THE PACE COMPANY CONSULTANTS & ENGINEERS, INC. 5251 WESTHEIMER
P.O. BOX 53473 HOUSTON, TEXAS 77052 AC 713 965-0311 CABLE: PACECO-HOUSTON TELEX 77-4350
A Member of Jacobs Engineering Group

OVERVIEW OF SHALE OIL DEVELOPMENT AND UTILIZATION

Prepared For

OCCIDENTAL OIL SHALE, INC.

For PACE

Ken L. Comontofski

Thomas J. Manning

November 1980

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A

INTRODUCTION

The Pace Company Consultants & Engineers, Inc., has assessed the technical, economic, and logistical factors involved with the utilization of shale oil. The issues analyzed in this study are:

- Potential and expected shale oil production
- Shale oil characteristics
- Potential products which can be made from shale oil and the supply/demand for these products
- Existing and new pipeline requirements and suitability
- Refining technology suitable for shale oil processing
- Investment and operating costs of shale oil processing
- Identification of refineries having potential to process shale oil.

B

SUMMARY AND CONCLUSIONS

CONCLUSIONS

This study identified several key issues which will have a significant effect on the cost, timeliness, and ease with which shale oil can be introduced into the United States' refining system.

Specific

- Occidental plans to blend shale oil naphtha back into the modified in-situ and surface retort raw shale oils to help alleviate potential pipelining problems. However, the estimated properties of the blend still leave it with a pour point in the range of 50°F to 55°F and viscosity of 50 to 60 SUS (at 100°F) which require tankage and handling similar to regional heavy asphaltic crudes. The Platte system is not capable of handling such pour point properties, therefore some form of pour point depressant will have to be considered.

- Occidental's composite raw shale oil will be of better quality than other area raw shale oil and as such will be in a better economic position. This will be true no matter what the intended use, fuel or refining feedstock.

- Due to the relative lower contaminant level and residual content of the Occidental composite raw shale oil the cost to upgrade it on-site will be at the lower end of the projected range of upgrading costs.

General

- Neither economic or resource availability will limit shale oil development through 2000. Realistic time schedules and man-power availability will determine shale oil production during the 1980s.

- The major obstacles in the way of long-term shale oil production will be engineering/construction and socio-environmental related problems.

- Existing crude oil pipeline systems may encounter difficulty in handling most raw shale oil's high viscosity, pour point, and contaminant levels. In addition, expansion of feeder lines will be required to allow movement of shale oil out of the oil shale region to tie-in with existing major pipeline systems. Excess capacity in these major pipeline systems is projected to be about 300 thousand barrels per day. Shale oil production in excess of this level will require new pipeline construction.

- Early production raw shale oil may initially be used as boiler fuel because refiners will require evidence of stable and consistent source of supply before they will invest the capital to refine shale oil in their facilities. A federal shale oil storage program might be feasible to supplement the Strategic Petroleum Reserve. This would allow later processing to transportation fuels.

- Additional large-scale tests of raw shale oil in industrial or utility boilers are needed to demonstrate techniques of nitrogen oxide emissions control.

- Shale oil upgrading onsite or in a regional facility would allow the integration of syncrude into the existing refining and pipeline systems at minimal disruption.

- A large fraction of any shale oil which is produced will be refined by the major oil companies who participate in the shale oil projects. These companies will be modifying their refineries to process shale oil.

- Refiners not in shale oil production may find their refineries are short of the required hydrogen needed for shale oil treating. Hydrotreating severity required to produce transportation fuels may exceed the design limits of processing units in many refineries. Those refineries which appear capable of processing raw shale oil, without capital investment, can only handle relatively small volumes and are also geographically dispersed.

- Shale oil can be refined to produce essentially all fuels produced from conventional petroleum. Based on refining technology and projected product demands to the year 2000, shale oil will be best suited to the production of diesel fuel and jet fuel.

- Most shale oil contains less light, low boiling point material and less heavy residual material than an average petroleum crude oil. The boiling range for shale oil is typically 160°F to 1,030°F. As refined product demand shifts to more middle distillates (kerosene, jet fuel, diesel, etc.) and less motor gasolines, the refining value of shale oil will increase relative to other crude oils.

- Based on refinery configurations, hydrogen supply, transportation systems, and crude availability, eleven refineries in Petroleum Administration for Defense Districts (PADDs) 2A and 2B have been identified as potential processors of shale oil. PADD 4 would require construction of major new refineries to allow processing of significant quantities of raw shale oil.

- The cost of processing raw shale oil as an alternate to petroleum crude oil is extremely variable, dependent upon the percentage of shale oil run in the refinery, as well as the availability of excess hydrogen.

- The value of typical raw shale oil to a PADD 2A refiner will be in the range of $3 to $4 per barrel (1980 dollars) less than the alternate, last increment, foreign import crude in 1985. This is based on differences in variable operating costs, product slate, and capital charges approximating a 10 percent DCF rate of return on the incremental investment (1980 dollars).

- Refining cost differentials between shale oil and conventional crude are most sensitive to incremental capital, particularly for the shale oil hydrotreater. For that unit, estimates ranging between $1,500 and $3,000 per barrel of capacity were found in the literature and a value of $2,730 per barrel was used in the general economics of this report.

SUMMARY

Production Forecast

Funding under the Synthetic Fuels Corporation is expected to firm up existing projects, but not result in any incremental production by 1990. During the 1990s the slow growth in production of conventional crude oil worldwide can be expected to spur shale oil development. However, due to the construction and operational requirements with the associated social problems, we forecast potential shale oil production in the year 2000 to fall considerably short of the total resource potential.

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Pace's shale oil production forecast is as follows:

Shale Oil Production
(Thousand Barrels Per Day)

	Low		High
1985	26	-	30
1990	250	-	350
1995	500	-	700
2000	1,200	-	1,500

Occidental is expecting to be producing 94 thousand barrels per calendar day by 1991, or approximately one third of our forecasted 1990 production.

Market Outlook

Shale oil can be refined to produce essentially all fuels produced from conventional petroleum. Two key qualities that will make shale oil an attractive feedstock are:

- The distillate fraction has a high cetane (octane) quality which makes products well suited to diesel and jet-A production. These products are expected to show good growth through the year 2000, while gasoline and residual fuel oil demand decline.

- The overall quality of the crude oils available for processing is expected to decline significantly. The resultant increased yields of bottom of the barrel material will require substantial capital investment in conversion processes to avoid a residual fuel glut. Because typical shale oils are likely to have little material boiling over 1,050°F, shale oil processing will reduce the need to add bottom of the barrel processing.

Use of whole shale oil as a boiler fuel may be an interim outlet during the early years when production is limited and on an intermittent basis. Due to the exemption from the Utility and Industrial Fuel Use Act regulations which restrict the use of natural gas or oil as a boiler fuel if in a mixture with an alternate fuel such as shale oil, those installations facing an expensive conversion may find shale oil use attractive. However, it is uncertain whether shale oil can be burned directly or blended with other fuel oils without excessive emissions of nitrogen oxides and/or particulates.

Transportation

Shale oil's high pour point and contaminant level will require special considerations for use in existing or new pipelines. Transportation in existing pipelines will require either, upgrading of the shale oil, dilution blending, or use of flow improving additives.

Two existing pipeline systems have the potential to transport shale oil. The northern and southern systems are shown in Figure B-1. Both systems will require construction of connecting lines to connect with the Piceance Creek oil shale facilities. The largest potential is in the northern system with the spare capacity in connecting pipelines as shown in the following:

Pipeline	Terminals	Excess Capacity (BPD)
Amoco (20-inch)	Elk Basin, Wyoming to Freeman, Missouri	45,000
Platte	Byron, Wyoming to Wood River, Illinois	120,000
Conoco	Gurnsey, Wyoming to Denver, Colorado	18,000
Arapahoe	Gurley, North Dakota to Hymboldt, Kanasas	100,000
	Total	283,000

In the southern system about 20 thousand barrels per day can be moved from the Pure Oil pipeline at Aneth to West Texas and the Gulf Coast. The ability of both systems to handle shale oil is dependent on conventional oil production levels and the distribution scheme for Alaskan North Slope oil in the area.

Therefore, total excess capacity in the existing major pipeline systems is about 300 thousand barrels per day. Shale oil production in excess of this level will require major new pipeline construction. These new systems would have heating capacity to handle high point oil.

Spur connection lines between the shale oil regions and the existing pipeline system will have to be built. The industry may consider a connection to the Platte system at Casper, Wyoming. It should have capability of about 200 to 250 thousand barrels per day in order to meet the needs of the current Colorado project capacities. At this size the spur line would cost about $81 million (1980 dollars) and would require a $0.80 to $1.00 per barrel tariff to make a 20 percent before tax return on investment at full capacity.

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Refining

Shale oil generally has a low API gravity, a moderate sulfur content, and a very high nitrogen content and pour point compared with conventional crude oils. The nitrogen content is a major problem because many nitrogen compounds act as a catalyst poison in many processing units. The high pour points present transportation problems as discussed earlier.

In order to fit into the refining industry raw shale oil will have to be high severity hydrotreated to reduce nitrogen content, especially in the 650°F to 1,000°F cut, which is typical fluid catalytic cracking feedstock. Occidental's raw shale oil will have to be 85 to 90 percent denitrogenated to make it suitable for refinery processing. The amount of hydrotreating necessary to upgrade raw shale oil will place a large majority of refineries in a hydrogen deficit position. Refineries currently with surplus hydrogen are limited in number and geographically dispersed. However, overall crude quality is expected to be decreasing, which will be requiring investment to cleanup, so hydrogen balances will most likely becoming tight even without shale oil processing. The largest deterrent to refining industry based shale oil upgrading is the economics of investment by size.

Hydrotreat processing is more economical in sizes of 20 thousand barrels per stream day and larger. Only about four shale oil production projects will reach this level of capacity before 1990. Hydrogen availability and cost will also determine whether the optimum location for hydrotreating is at the shale oil facility or at the refinery. Residuum hydrodesulfurization makes it possible to hydrotreat whole shale oil without fractionation. Onsite upgrading will be attractive for a surface retort that produces a high BTU gas which can be used as a feedstock for hydrogen generation.

Economics

In this study we have looked at not only the general economics of onsite (upfront) upgrading of raw shale oil, downstream upgrading of raw shale oil but also specific onsite upgrading of Occidental's raw shale oil at their plant site.

These results indicate that typically raw shale oil will be worth between $2.00 to $3.00 per barrel less than imported foreign crude to a typical PADD 2A refiner (during the 1980 to 1990 period) if he has to put in either raw shale oil treating or downstream treating. The general cost of upfront raw shale oil treating is between $7.00 to $10.00 per barrel (1980 dollars) depending on the size of the unit and the value of the hydrogen consumed. The site-specific economics of Occidental upgrading its own shale oil onsite looks like $6.00 per barrel (1980 dollars) assuming a 50 thousand barrel per stream day unit and a 3.5 cents per kilowatt hour (1980 dollars) value of area power.

The reason that raw shale oil has a value only $2.00 to $3.00 less than an imported crude instead of $6.00 to $9.00 is because the shale oil has an inherent value of $4.00 to $6.00 per barrel greater due to the fact of its composition with very little if any material in the 1,000°F+ range.

The netback value of Occidental's raw shale to the Occidental plant will be between $27 to $48 per barrel (1980 dollars) during the 1985 to 2000 time frame with an average of around $36 to $37 per barrel.

Estimated Netback Value Of Occidental's Raw Shale Oil
(1980 Dollars Per Barrel)

	1985	1990	1995	2000
PADD 2A Refining Value	29.01	35.28	42.21	50.32
Less: Platte Cost	0.83	0.91	1.00	1.10
Less: Spur Line Cost	1.53-2.75	1.53	1.16	0.79
Netback ($/Bbl)	26.65-25.43	32.84	40.15	48.43

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C

SHALE OIL SUPPLY/DEMAND

PRODUCTION OUTLOOK

Although shale oil is now competitive with conventional petroleum, major uncertainties and risks remain.

Pace evaluated the following factors in developing a forecast of shale oil production to the year 2000:

- Production economics
- Environmental challenges and impact of an Energy Mobilization Board
- Funding under the Synthetic Fuels Corporation
- Status of existing projects
- Access to shale oil resources
- Impact of large scale development on the remote, local communities
- Market outlook for shale oil derived products.

Our estimates of production between 1985 and 2000 are summarized in the following table:

Shale Oil Production
Thousand Barrels Per Day

	Low		High
1985	5	-	25
1987	100	-	150
1990	250	-	350
1995	500	-	700
2000	1,200	-	1,500

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TABLE C-1

OIL SHALE PRODUCTION PROJECTS
Capable of Supporting Commercial Oil Shale Projects
(Potential Fee, Federal, and State Leases)

Company and/or Project	Estimated Production Rate (Barrels Per Day)	Announced Start-Up Date
Colorado		
Arco	-	-
Occidental Shale Oil	12,000 (93,800)	1986 (1991)
Cities Service	-	-
Chevron Shale Oil Company	10,000-50,000	1988
Colony Development Corporation	46,000	1985
Getty	-	-
Mobil-Arco-Equity	-	-
Mobil Oil	-	-
Rio Blanco Oil Shale Company	76,000	1987
Sohio-Cleveland Cliffs	-	-
Superior Oil*	11,600	1989
Texaco	-	-
Union Oil Company	10,000-50,000	1985
Utah		
Geokinetics	2,000	1982
Sohio-Cleveland Cliffs	6,000-10,000	1983
Tosco Sand Wash	50,000	1987
Tract U-a and U-b	50,000-100,000	1990+
Total Announced Capacity Before 1990	223,600-307,600	Before 1990

* Existing property assumed to be developed on a multi-mineral basis—may not support 50,000 barrels per day shale oil production.

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Neither economics or resource availability will limit shale oil development through 2000.

Near Term Production (1980-1990)

Shale oil production during the 1980s is tied to realistic project time schedules. With the establishment of The Synfuels Corporation under the Energy Security Act of 1980, those companies which currently have a viable resource position will most likely reach full scale production by 1990.

We have constructed project development schedule for projects currently with access to a suitable resource but without an existing development plan. This time schedule assumes that a governmental agency such as the Energy Mobilization Board will be established to speed up the permitting process. The schedule is as follows:

6/81	Energy Mobilization Board (EMB) authorized by Congress
6/82	EMB identifies fast track projects and establishes Project Development Schedules
6/82-6/94	Environmental monitoring, reporting and permitting completed
6/94-6/89	Construction
6/89+	Operation.

With this time schedule, a new project would have to be well enought defined by mid-1982 to be identified by the EMB as a "fast-track" project in order to begin operation by 1990.

In forecasting short term production levels we have analyzed the patented or leased shale oil properties capable of producing 50,000 barrels per day of shale oil for 30 years. These properties are identified and their current development status are listed in Table C-1. The total announced shale oil production capacity as of mid-year 1980 is between 224 and 308 thousand barrels per day by 1990. This total is subject to upward adjustment in the 1990 time frame by establishment of new projects by property holders who have not yet announced projects, and to downward adjustment due to schedule slippage for announced projects. Although the Synfuels Corproation is expected to improve the outlook for announced projects, no incremental shale oil production can be expected as a result of additional federal funding by 1990. If a new federal oil shale leasing program is not implemented, these properties will most likely set shale oil production past 1990.

Long Term Production (1990-2000)

During the 1990s the decline in production of conventional domestic crude oil and continued dependence on foreign sources can be expected to spur shale oil development based on current technologies. We estimate maximum total Colorado and Utah production, based on in-place resources from existing properties would be in the 1.2 to 1.5 million barrels per day range:

Facility Type, Size and Number	Thousand Barrels Per Day		
4 Underground Mines/Surface Retorts @ 80 - 100 MBPD	320	-	400
3 Modified In-Situ @ 80-100 MBPD	240	-	300
4 Underground Mines/Surface Retorts @ 40-50 MBPD	120	-	200
5 Modified In-Situ @ 40-50 MBPD	200	-	250
1 Surface Mine/Surface Retort @ 240-300 MBPD	240	-	300
Total Production Potential	1,200	-	1,450

In the 1990 to 2000 time frame new blocks of shale oil are expected to be leased by the Federal government. It is uncertain whether these leases will be issued under an expanded Federal Prototype Oil Shale Leasing Program or a new, permanent program. Discussions to this date indicates that new leases under the existing prototype program would be issued in August 1983. There have also been preliminary indications that four leases would be made available, one being a multi-mineral lease in Colorado, and three others chosen with minimization of socio-economic impacts as a major criterion. (This would significantly favor Utah or possibly Wyoming.)

At any rate, the additions of at least four more federal leases to the existing developable resource base will certainly push production potential by 2000 to two million barrels per day or greater. However, it is our contention that shale oil production during the decade of the 1990s is most likely to be limited by the development of bottlenecks due to massive construction and operational requirements in a limited geographical area with very little existing infrastructures. Therefore, we forecast shale oil production in 2000 to be 1.2 million barrels per day, somewhat less than the total potential.

Commercial Plans

Occidental plans to produce two types of raw shale from the Occidental tract. The majority of production will come from a modified in-situ process and the remainder will be from surface retorting of the in-situ mined material.

Occidental Production Plan

	(MMB/Yr)			(MBPCD)
	MIS*	SR**	Total	Total
1985	0.38	0.44	0.82	2.2
1986	3.30	1.10	4.40	12.1
1987	10.00	1.98	11.98	32.8
1988	15.58	4.41	19.99	54.8
1989	20.14	8.75	28.89	79.2
1990	20.14	12.65	32.79	89.8
1991	20.14	14.10	34.24	93.8

* Modified in-situ
** Surface retort

Government Funding

High costs, long lead times, and technical risks has precipitated government involvement in shale oil development. The Energy Security Act of 1980 also provided $20 billion in funding for the development of synthetics fuel sources, with the potential for an additional $68 billion during the twelve year lifetime of the Synthetic Fuels Corporation. However, only the initial $20 billion will have an impact by 1990. This $20 billion will have to be matched with $7 billion from industry making the total invested at $27 billion.

We have assumed that the $27 billion will be distributed as follows:

- 25 percent shale oil
- 50 percent coal synfuels
- 25 percent other.

Oil shale's share of the available funds reflect a lower need for economic incentive and less political support in comparison with coal synfuel projects. The following schedule of expenditures was also assumed:

Estimated Synfuels Expenditures
(Billion Dollars)

Year	Total Expenditures	Shale Oil	
		Current Dollars	Year-End 1980 Dollars
1981	2.0	0.5	0.4
1982	3.3	0.8	0.8
1983	5.3	1.3	1.0
1984	6.7	1.6	1.2
1985	9.3	2.3	1.5
Total	26.6	6.7	4.9

At an approximate shale oil production investment of about $32,000 per daily barrel (year-end 1980 dollars), this level if used in direct funding would support about 150 thousand barrels per day of production. However, if this is used primarily for loan guarantees the loan leverage would be about 3:1, thereby supporting about 450 thousand barrels per day production. It is Pace's assessment that these funds will primarily go to those projects which are already on the drawing boards, and the net result will be that some of the uncertainty will be removed from already announced projects. The 1990 projection for shale oil production therefore reflects the fact that Synthetic Fuels Corporation funding will "firm up" already announced projects.

The small congressional representation of Colorado and Utah could be a negative factor to shale oil development as officials in other areas will also be vying for available government funds.

Social/Environmental Pressures

Pace believes that the long-term limitation on shale oil production will be adverse growth considerations in the shale oil region. The fear of disruption and pollution of critical surface and underground water systems, severe degradation of air quality, destruction of aesthetics, problems of reclamation, and runaway boom town environments are some of the factors that will inhibit shale oil development. The current Colorado state administration lamely supports some sort of phased, modular development, but no major program.

Even with very orderly development, severe growth problems are probable in Colorado which will likely result in anti-growth sentiment. As a result of this anti-growth sentiment, shale oil devleopment will accelerate in Utah and eventually Wyoming in the period between 1990 and 2000. Although Colorado's share of shale oil production will continue to increase, capacity addition to existing facilities is likely to be favored over new grass roots facilities.

Each 50,000 barrel per day shale oil plant will employ 2,000 people directly, with a multiplier of 5.5 applied to the number of employees to arrive at total population increase. This is equivalent to a population increase of 11,000 people per plant. A peak construction force of 2,000 people is estimated per plant. The population mulitplier for construction workers would normally be about two and one half. However, if the construction of plants is undertaken in a sequential fashion over many years, the construction jobs will essentially become permanent rather than transient. This increases the multiplier, and a value of 4.0 is probable.

Physical and Technical Aspects

There are no serious physical constraints to the availability of shale oil resources through the end of this century. Water availability, which is usually a prime concern in the western United States, does not present any limiting problem to currently projected synfuels projects. All companies with major shale oil holdings also have tied down water rights for their projects. No water limitation is foreseen up to a 2 to 3 million barrels per day production level.

The richest and largest deposits of shale oil are in northwestern Colorado, northeastern Utah, and in southwestern Wyoming. These areas, covering thousands of square miles, are primarily undeveloped land. The Green, White, and Colorado rivers flow through or around much of this area. About 80 percent of the prime shale oil land is owned by the Federal government. Large deposits of shale oil exist in the East (Devonian shale) but are of lower quality than western shale, and little development work has been done.

A number of above-ground shale oil retorting processes are ready for commercial operation. These include processes developed by Union Oil, Tosco, Paraho, Lurgi, Superior Oil, and Petrosix. There is no established class of "second generation" retorting processes available in the foreseeable future. Occidental Oil Shale has developed a modified in-situ process they are ready to commercialize. Rio Blanco Shale Oil is testing a similiar process and if sucessful will go commercial.

Much work has been done on the development of oil shale retorting processes, and many apparently suitable processes have been demonstrated successfully at pilot plant scales. No modern process has been demonstrated at a commercial scale of operation—an operating rate deemed to range from 4,000 to 10,000 tons of shale feed per day for a single module. Despite this lack of a commercial demonstration in the United States, some firms appear willing to proceed to the commercial scale with retorting technologies which have been well demonstrated in large pilot plants.

The high mineral content of shale oil and oil sands is of great concern since large volumes of solids must be processed and then stored in waste disposal sites. Because of this, in-place (modified in-situ) recovery processes are being developed. Modern mining equipment and methods have been demonstrated satisfactorily in several shale oil mine development projects. Except for orchestrating the tremendous scale of commercial operations, mining methods do not require major technical innovations.

There are also considerable refining problems. Limited quantities of shale oil can be used in mixed feedstocks to some refineries. However, increases in hydrogen are required to upgrade shale oil if it is to be used in large quantities. The high nitrogen content in shale oil also makes large quantities of this particular synthetic fuel troublesome as a refinery feedstock, since it causes catalyst poisoning. Traditional and proven hydrotreating processing can and will be used to overcome these characteristics.

REGIONAL REFINED PRODUCT DEMANDS

As previously discussed, shale oil can be refined to produce essentially any fuel produced from conventional petroleum. However, it is our judgment that shale oil will be targeted toward four markets:

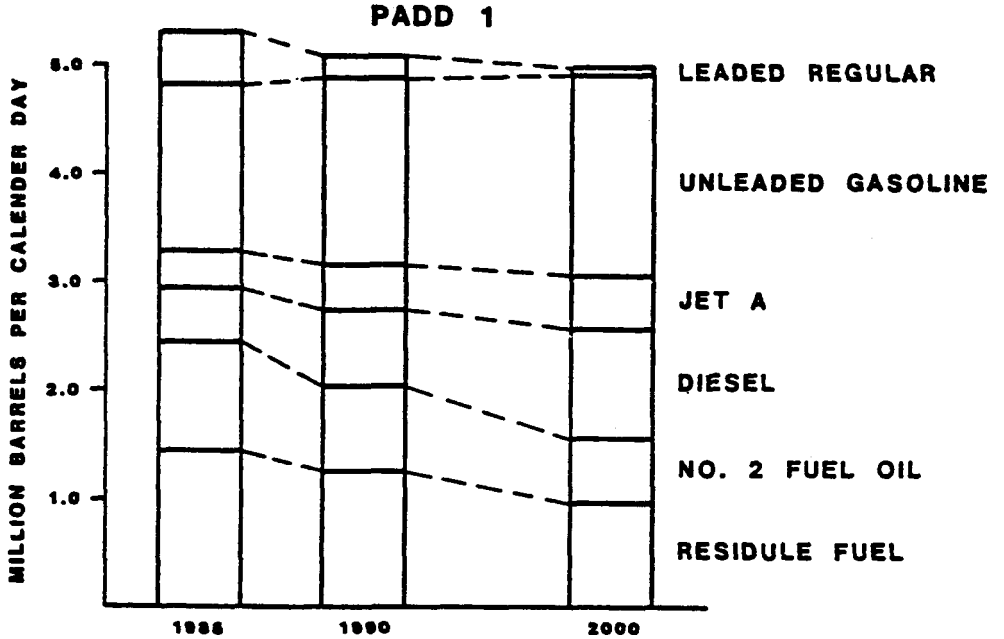
- Transportation fuels (primarily jet fuel and diesel fuel)
- Distillate fuel oil
- Low sulfur fuel oils normally used by industry and utilities as boiler fuel
- Refinery fuel.

Growth in refined product demand by PADD through the year 2000 is shown in Figure C-1. This forecast is from the Spring 1980 edition of "The Pace Energy and Petrochemical Outlook to 2000." A map of the United States by Petroleum Administration for Defense District (PADD) is shown in Figure C-2.

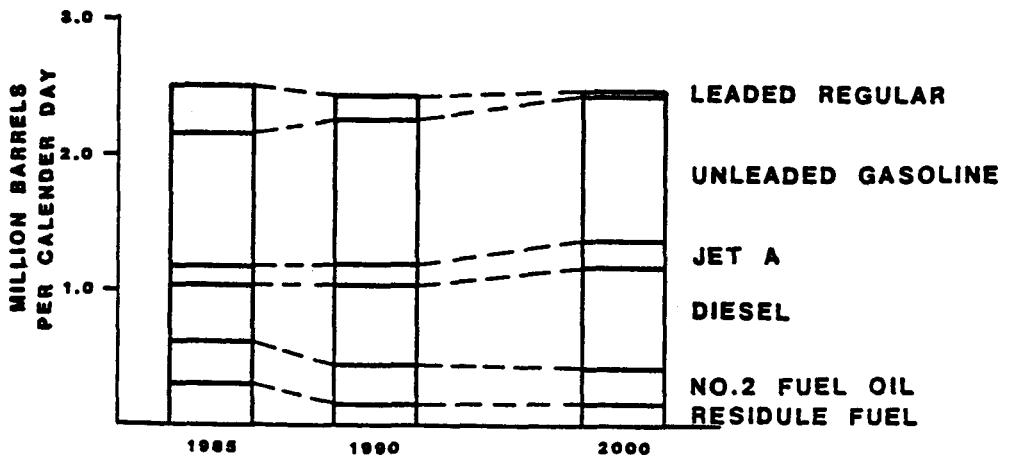
FIGURE C-1

PROJECTED REFINED PRODUCT CONSUMPTION
MILLIONS OF BARRELS PER CALENDER DAY

PADD 1



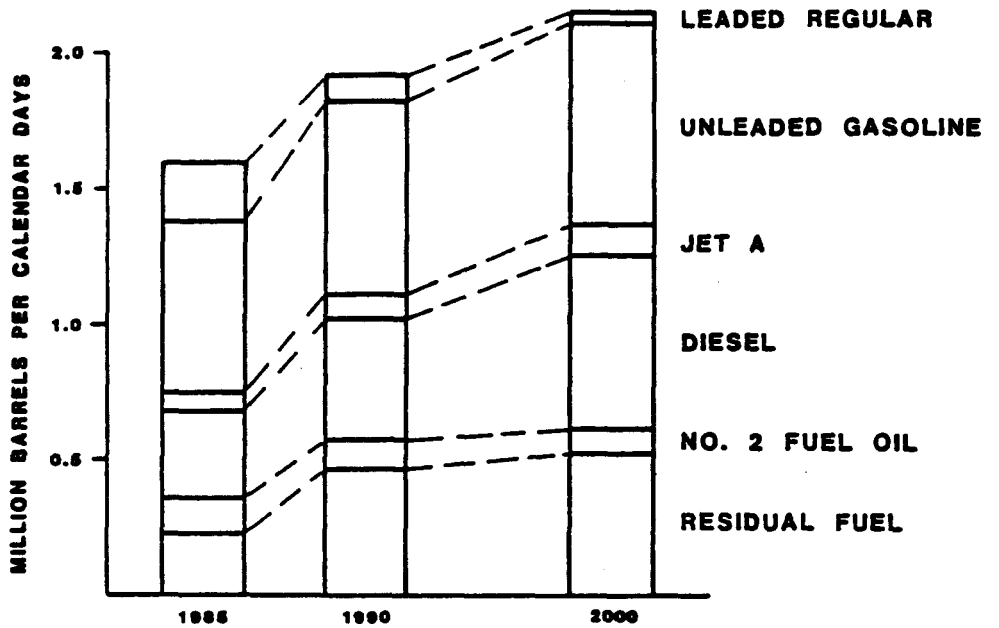
PADD 2A



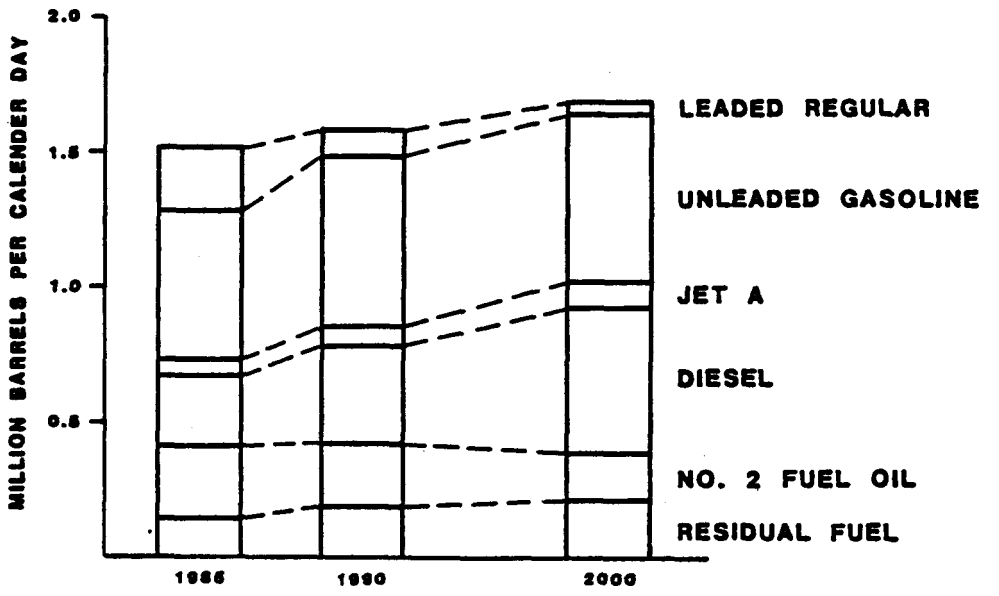
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FIGURE C-1(CONT)

PADD 3



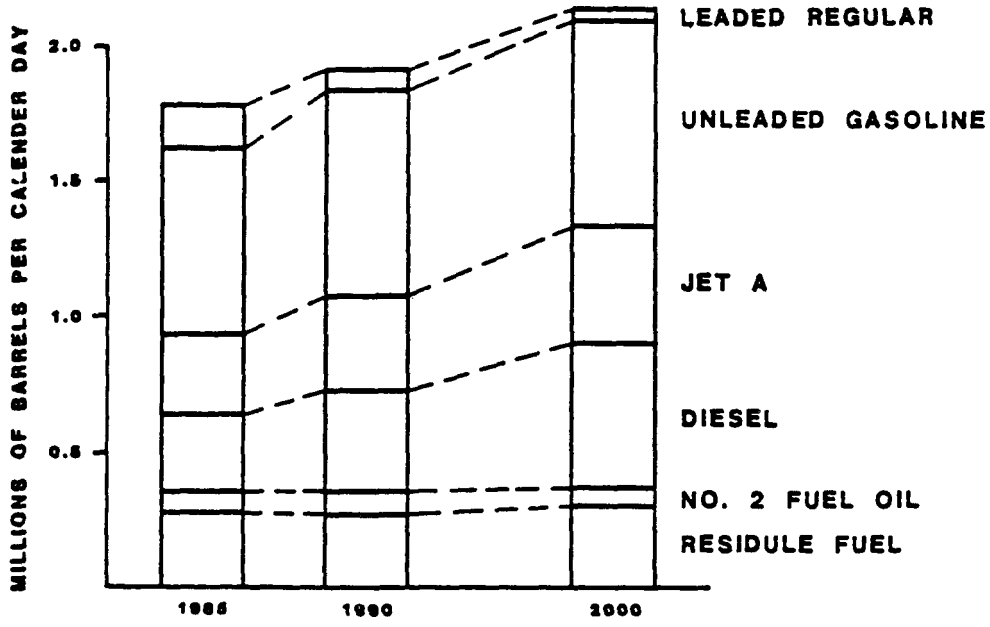
PADD 2B/4



640

FIGURE C-1 (CONT)

PADD 5



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Shale oil is well suited to the production of diesel and jet fuel. The diesel fraction produced is a high quality fuel with a cetane number near 55 (versus 42 to 45 minimum for specification diesel) and a smoke point and pour point well within the ASTM standard. The heavy naphtha fraction also shows good jet fuel qualities. Partially upgraded shale oil can be blended with the distillate fraction of other crude oils to produce distillate fuel oil. Growth in demand for all distillates is summarized in the following:

1985-2000 Distillates Demand Growth
Percent Per Year

	PADD 2A	PADD 2B/4	PADD 3	PADD 5	Total U. S.
Jet A	1.3	3.0	4.5	2.4	2.2
Diesel	4.5	5.0	4.6	4.7	4.8
Distillate Fuel Oil	(2.3)	(2.4)	(1.1)	(1.8)	(2.1)

With the substantial growth in diesel fuel, the production of diesel from shale oil is desirable from a refining standpoint since it fits the supply/demand trend.

While diesel and jet fuels are expected to show good growth, total gasoline consumption is expected to decline. While residual fuel demand may grow in some regions, total United States consumption is expected to be flat at 2.5 to 2.6 million barrels per day. Trends in demand for gasoline and residual by region are shown in the following:

1985 - 2000
Gasoline and Residual Demand Trends
Percent Per Year

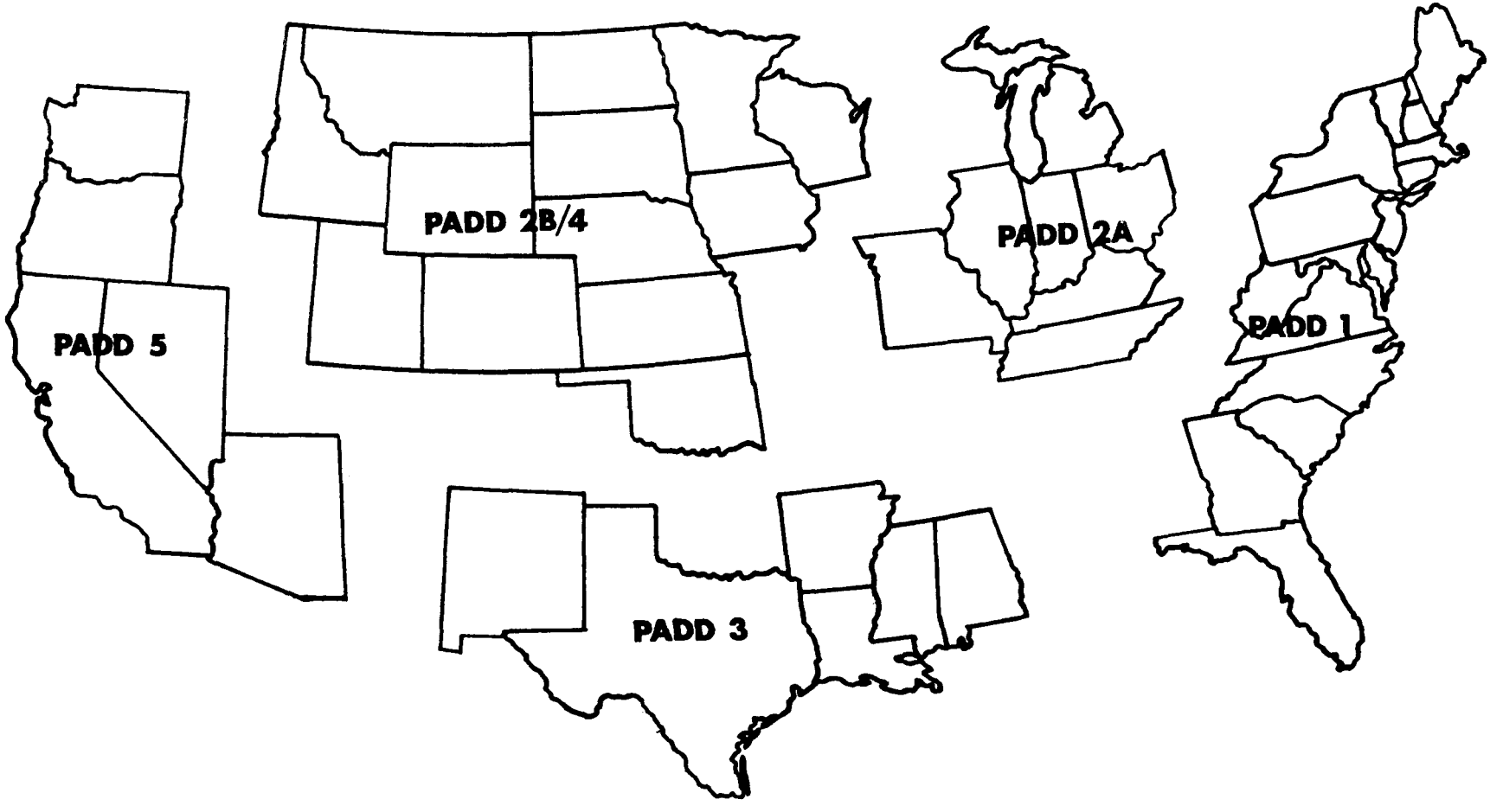
	PADD 2A	PADD 2B/4	PADD 3	PADD 5	Total U. S.
Leaded Gasoline	(11.6)	(11.5)	(10.5)	(9.7)	(9.8)
Unleaded Gasoline	0.4	0.7	0.9	0.8	0.8
Residual Fuel Oil	(3.2)	2.0	5.0	0.7	0.0

Based on the requirements for a high aromatic content to meet octane requirements, naphtha shale oil fractions are suitable feedstock for gasoline reforming. Displacement of other more aromatic fractions from other oils which are not currently used in gasoline production is probably the best disposition of the shale oil's naphtha fractions.

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FIGURE C-2

PETROLEUM ADMINISTRATION for DEFENSE DISTRICTS - PADD



In addition to the favorable fit between shale oil properties and the projected growth markets for diesel and jet fuel, shale oil also has other benefits to the refining industry. Figure C-3 shows Pace's projection of the composite crude quality available to United States refiners to the year 2000. The increased yields of bottom-of-the-barrel material will require substantial capital investment in conversion processes to avoid a glut of residual fuel. The increasing sulfur content of available crudes will act to eliminate the availability of excess hydrogen in many refineries. The reversal of sulfur level and the slowdown in heavy-ends in 2000 is due to our inclusion of 1.5 million barrels per day of shale oil in refinery runs.

If shale oil is upgraded on site to take advantage of lower hydrogen costs available from retorting operations, the resulting syncrude can be processed by nearly any large-scale refinery. Because the syncrude is likely to have an end point of about 1050°F, shale oil processing will reduce the need to add bottom-of-the-barrel processing at the refinery. This will make shale oil a very attractive feedstock to refiners faced with a resiudal fuel bottleneck.

Market uncertainties which face the United States energy supply/demand balance pose a minimal down side risk for shale oil as compared with other alternatives. Key considerations are:

- Higher world oil prices will act to make shale oil which is already economically viable even more so. In addition the higher prices would bring about even further convervation. Pace's analysis of the impact of additional conservation is that gasoline and residual fuel consumption would be the most strongly affected, and the requirement for addition of bottom-of-the-barrel processing would be increased. Although lowered gasoline consumption would not impact directly on shale oil's primary markets, the residual fuel problem would increase shale oil's market value.

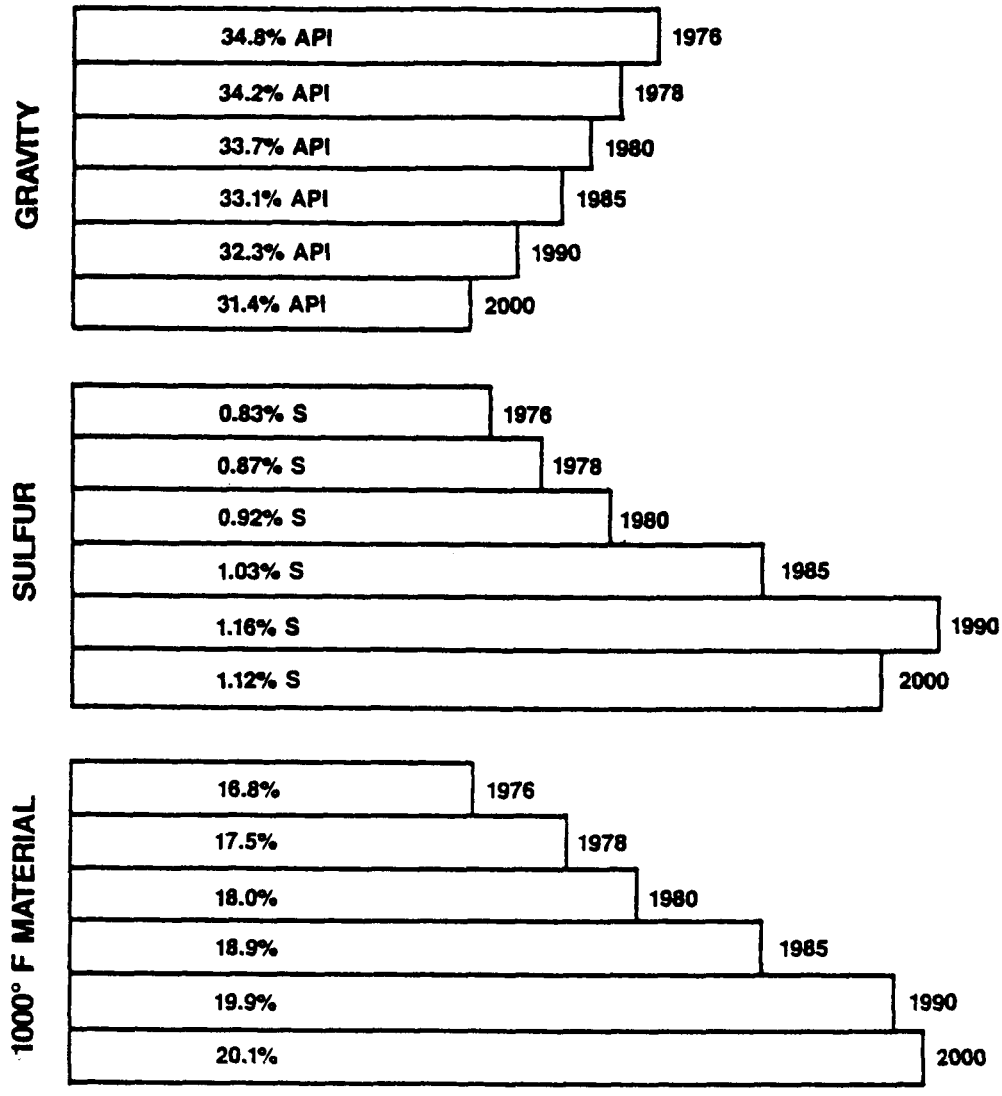
- Reduced residual fuel demand can result from higher conservation levels, forced conversion of existing oil-fired boilers to coal, and increased competition from additional natural gas supplies. Such a reduction in residual demand would require additional refinery investment to destroy residual. Again, this would increase the attractiveness of shale as a feedstock.

Direct Use as a Boiler Fuel

During the initial years of production, shale oil will be produced in low volumes and on an intermittent basis due to startup and shutdown of a limited number of production modules. During these initial years when production is getting underway the use of raw shale oil as boiler fuel could provide a valuable outlet for supplies from both a timeliness and quality standpoint.

FIGURE C-3

KEY
CHARACTERISTIC OF CRUDE RUNS TO STILLS



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Some uncertainty still exists as to whether shale oil can be burned directly or blended with petroluem fuel oils without excessive emissions of nitrogen oxides and/or particulates. A large-scale test firing of shale oil/fuel oil blends was conducted in 1976 by Southern California Edison in a 45 megawatt boiler. The boiler was equipped with six front-face mounted oil burners arranged in two rows. These tests showed that in order to meet a nitrogen oxide emission restriction of 225 ppm which applies in Southern California, a blend of up to 17 percent shale oil (1.98 weight percent nitrogen) could be burned using specially designed low nitrogen oxide burners and staged combustion techniques. If a shale oil blend was to be burned in the bottom row of the burner and natural gas burned in the upper row, a blend of up to 58 percent shale oil could be used and still meet the emission restriction.

The results are particularly significant when interpreted in light of the Utility and Industrial Fuel Use Act. This Act is intended to minimize the use of natural gas and petroleum in new and existing power plants and major fuel burning installations. However, the Act provides, for an exemption from the prohibition against the use of natural gas or oil if a mixture of gas or oil and an alternate fuel (such as shale oil) is used. If raw shale oil can be combusted without nitrogen oxide problems, those installations facing an expensive conversion from natural gas or oil-fired equipment to coal-fired equipment may find shale oil use attractive.

In our judgment this is a critical area which needs to be explored further because the use of raw shale oil as utility fuel could provide an important and useful outlet for this material during the early developmental stages of the shale oil industry. Use as a boiler fuel would also displace other residual fractions which might be more suitable for upgrading to gasoline and distillates.

D

SHALE OIL REFINING AND DISTRIBUTION

GENERAL

Raw shale oil is a valuable source of hydrocarbons which can be used to supply any end use normally associated with conventional petroleum products. As with conventional crude oils, shale oil must be refined to remove undesirable contaminants and to meet product specifications. Conventional petroleum refining processes can in principle be used to upgrade shale oil. However, processing equipment, operating conditions, and catalysts may require modification to handle shale oil's particular characteristics.

PHYSICAL PROPERTIES

The properties of raw shale oil differ depending upon the type of retorting process used. The most significant differences are apparent between shale oils produced by surface retorting and shale oils produced by in situ retorting.

Table D-1 compares the properties of six raw shale oils produced by different retorting processes. The Tosco, Union, and Paraho processes employ surface retorting. The Occidental process utilizes modified in-situ retorting. For comparison, the properties of four conventional petroleum crudes which will likely compete with shale oil for refining capacity are also shown. The typical range in shale oil properties is summarized below.

Shale Oil Quality

	Surface Retort	In-Situ Retort
Gravity, °API	19 - 22	24 - 25
Sulfur, Wt.%	0.6 - 0.8	0.6 - 1.2
Nitrogen, Wt.%	1.8 - 2.2	1.1 - 1.3
Pour Point, °F	60 - 85	50 - 60

TABLE D-1

COMPARISON OF SHALE OIL AND CONVENTIONAL PETROLEUM PROPERTIES

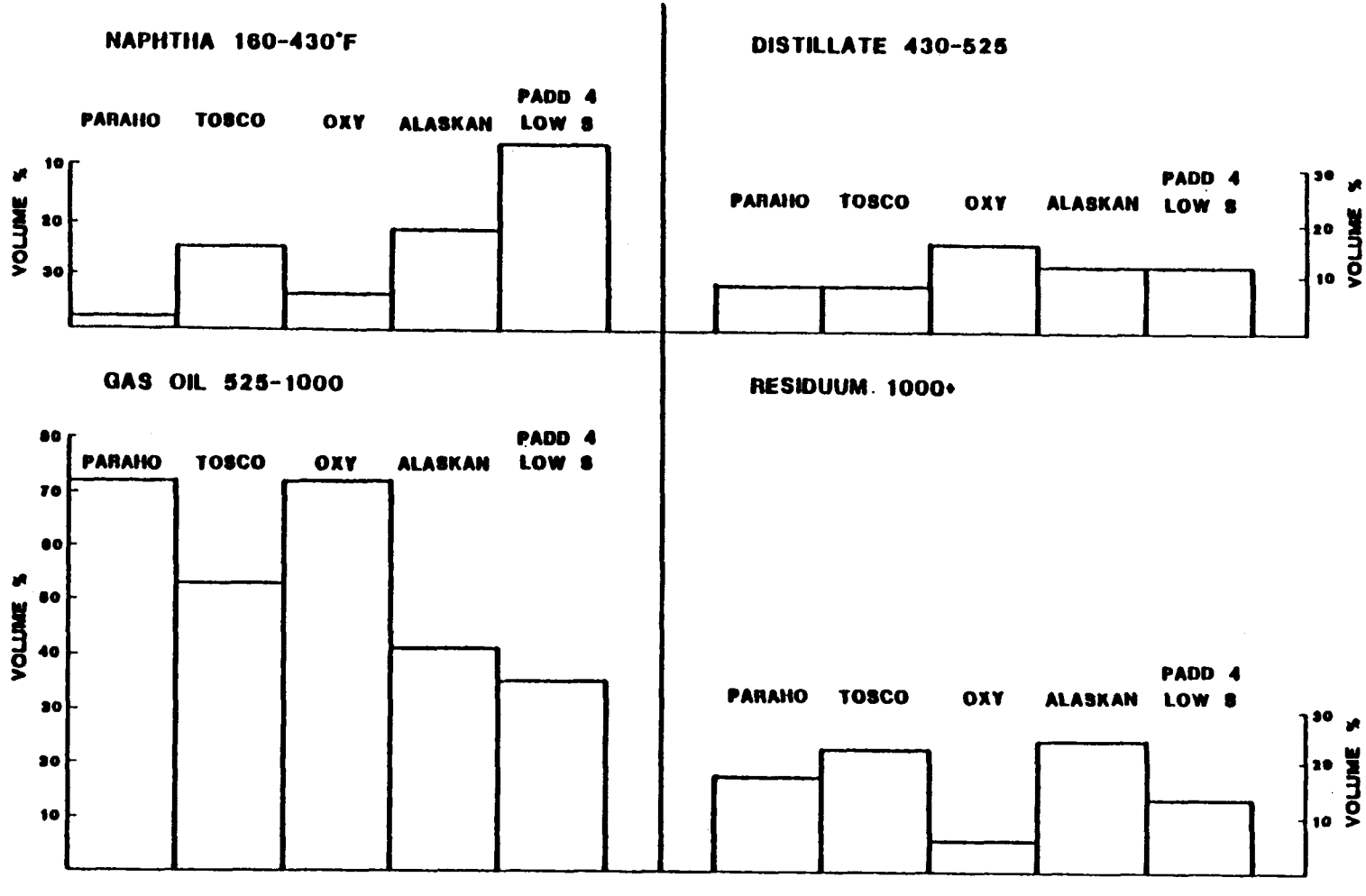
	API Gravity	Sulfur (Wt. %)	Nitrogen (Wt. %)	Pour Point °F
Raw Shale Oils				
Surface Retorting				
Tosco	21.0	0.67	1.85	70
Paraho Direct	19.3	0.71	2.00	85
Paraho Indirect	19.7	0.63	2.16	85
Union	22.2	0.80	1.80	60
Modified In-Situ Retorting				
Oxy	23.7-24.3	0.9-1.20	1.1-1.4	50-60
Petroleum Crudes				
Alaskan North Slope	27.5	0.96	0.04*	30
PADD 4 Low Sulfur	39.0	0.18	0.03*	7
PADD 4 High Sulfur	26.2	2.25	0.01*	0
PADD 4 Asphaltic	23.0	2.70	0.01*	0
California Heavys	19-24	1-2	0.1-0.3*	0

*Nitrogen contents for petroleum crudes based on 525°F to 1,000°F cuts.

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FIGURE D-1

COMPARISON OF FRACTION RECOVERABLE FROM SHALE OIL AND CRUDES



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TABLE D-2

SULFUR CONTENT OF CRUDE OIL PROCESSED IN UNITED STATES REFINERIES (Weight Percent Sulfur)

	PADD (Disposition)					
	1	2	3	4	5	Total U.S.
Domestic						
1985	0.83	0.61	0.72	1.50	1.07	0.84
1990	0.86	0.63	0.79	1.46	0.93	0.84
2000	0.84	0.60	0.71	1.48	0.92	0.80
Foreign						
1985	1.20	1.17	1.42	0.65	0.30	1.26
1990	1.23	1.43	1.50	-	0.31	1.37
2000	1.29	1.54	1.62	-	0.33	1.43
Composite						
1985	1.14	0.86	1.16	1.48	0.91	1.03
1990	1.15	1.03	1.23	1.46	0.82	1.16
2000	1.18	1.06	1.02	1.48	0.82	1.12

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As shown shale oil generally has a low API gravity, a moderate sulfur content, and very high nitrogen content and pour point compared with conventional crude oils. Figure D-1 compares the volumes of naphtha, distillate, gas oil, and residuum recoverable from three shale oils with two petroleum crudes. The figure shows that many raw shale oils contain small volumes of the gasoline, diesel, kerosene, and jet fuel fractions (naphtha and distillate) and large volumes of the fuel oil fraction (gas oil and residuum). This clearly illustrates the need for conversion processes such as coking, hydrocracking, and fluid catalytic cracking if a significant portion of the shale oil is to be used to produce transportation fuels.

Pace's forecast of the sulfur content of the domestic and foreign crude oils processed in United States refineries by PADD through 2000 is shown in Table D-2. The composite sulfur level compares with that for shale oils as shown in the following:

Sulfur Content
(Weight Percent Sulfur)

Shale Oil

Surface Retorts	0.6 - 0.8
Modified In-Situ	0.9 - 1.2

	PAD District				Total
	2	3	4	5	U. S.
Composite Crude Runs					
1985	0.9	1.2	1.5	0.9	1.0
1990	1.0	1.2	1.5	0.8	1.1
2000	1.1	1.0	1.5	0.8	1.1

As shown, shale oil from surface retorts will be lower in sulfur content than the average oil processed in all PADDs through the year 2000. Shale oil produced by modified in-situ retorting will be lower in sulfur than that typically processed in PADD 4 and comparable to that in PADD 3. However, because denitrogenation controls refining severity, a high degree of desulfurization is accomplished during denitrogenation.

The nitrogen content of raw shale oil is extremely high in comparison with petroleum crudes. The average nitrogen content of domestic crude oils is about 0.15 weight percent, which is an order of magnitude less than for shale oil. The nitrogen content of shale oil is of primary concern because many nitrogen compounds act as a catalyst poison in refinery processes which are used to upgrade shale oil. Secondarily, nitrogen compounds adversely affect the thermal stability of transportation fuels with resultant gum formation and also contribute to nitrogen oxide emissions.

The high pour points which are characteristic of most raw shale oils present problems in transporting the shale oil. Special handling procedures such as the use of heated pipelines, pour point depressants, and onsite upgrading have all been considered as means of alleviating these handling problems.

In addition, shale oil contains appreciable concentrations of oxygen, arsenic, iron, and in some cases finely dispersed particulate matter. Typical concentrations of these materials in shale oil are as follows:

Oxygen (Weight Percent)	0.8 - 1.4
Arsenic (ppm)	18 - 33
Iron (ppm)	33 - 108
Bottom Sediment and Water (Volume Percent)	0.2 - 0.7

Oxygen compounds are removed during hydroprocessing but add to hydrogen consumption during refining. Arsenic compounds accumulate on hydroprocessing catalysts and reduce their activity. It has also been shown that the arsenic, in the presence of the relatively high concentrations of iron in the shale oil, contributes to the formation of solid deposits in the hydroprocessing reactor. Equipment plugging due to such deposit formation has occurred in many of the laboratory-scale shale oil refining programs.

Depending upon the retorting method used, raw shale oil may contain significant amounts of mineral material as carry-over from the retorting process. These finely divided solids, along with entrained or emulsified water, show up in analyses for bottom sediment and water (BS&W). A solids removal step will be required prior to processing to prevent plugging of downstream refining processes. The arsenic and bottom sediment and water potential problems will be handled by the use of guard reactors which is standard refining industry practice in similar conditions.

SHALE OIL PROCESSING

Pretreatment

In order to process shale oil in a conventional refinery, provisions must be made to handle those requirements which are not typically dealt with in petroleum processing. We have termed the conversion of shale oil into a suitable refinery feedstock as "pretreatment". In some instances, pretreatment may include what the oil shale industry commonly refers to as upgrading. In the industry context, upgrading generally refers to onsite processing to produce a syncrude for pipelining to refining centers. Thus, upgrading represents extensive pretreatment which is the first stage of a two-stage refining scheme.

The question of whether to provide pretreatment/upgrading onsite or at the refinery location must be considered on a case-by-case basis. Key considerations are:

- Raw shale oil properties (which vary with the retorting process)
- Disposition
- If refined, how and where.

The next stage of complexity in shale oil pretreatment is encountered when raw shale oil is to be transported by pipeline to distant refining centers for processing. The use of pipelines for transportation imposes two requirements:

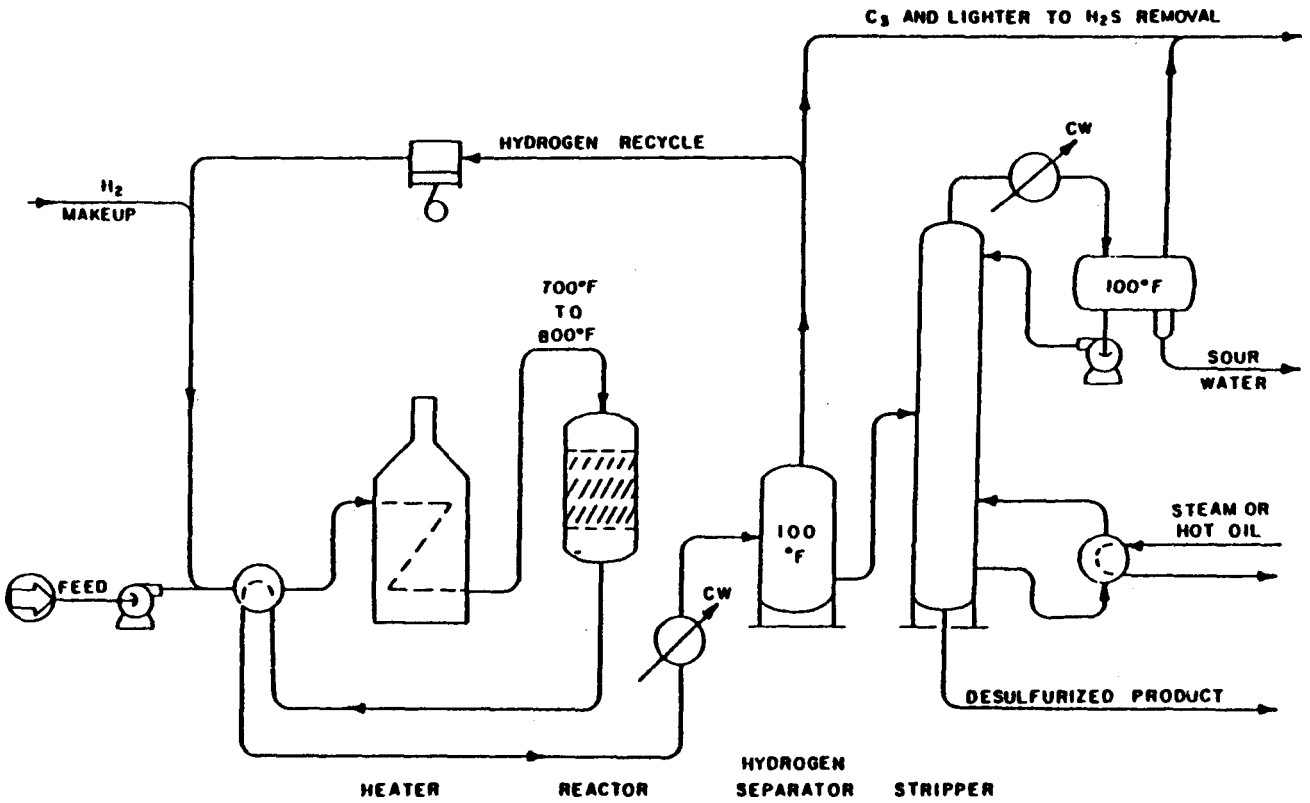
- The facility must be designed to handle the high pour points of raw shale oil or the pour point must be reduced.
- The shale oil should be relatively free of solids.

It is readily apparent that raw shale oils having a pour point of 60°F to 85°F cannot be transported through pipelines where the average ground temperature may be 40°F to 50°F without special facilities or pour point modification. Several options exist to overcome the pour point problem. These include:

- Construction of shale oil-dedicated, high-volume heated pipelines
- Use of proprietary pour point depressants to lower the pour point of the raw shale oil
- Use of proprietary shale oil preparation techniques which essentially slurry wax crystals of high pour point shale oil fractions in a low pour point shale oil fraction
- Chemical conversion of the raw shale oil by processes such as coking to remove high pour point materials.

FIGURE D-2

GENERALIZED HYDROTREATER SCHEMATIC DIAGRAM



Solids removal can be accomplished by several techniques. Gravity settling at elevated temperatures will remove substantial amounts of both water and oil shale fines. The particulate matter in raw shale oil could also be removed with small-pore filters which are currently in use to remove particulates from crude oil residuum prior to hydrodesulfurization. This can also be accomplished by continuous centrifuges or electrostatic heater treaters. Most refineries are equipped to remove any additional fines which might remain entrained in the shale oil. by electrostatic deslating.

Refining

The technology of conventional petroleum refining has advanced to the point where the substitution of an alternate feedstock such as shale oil does not require state-of-the-art advances in technology. Essentially any product which can be produced from conventional petroleum feedstocks can also be produced from shale oil.

Many options are possible for processing shale oil in a refinery. Very large refineries, which are typical of the Gulf Coast or Upper Mid-Continent (150 thousand barrels per day or greater capacity), have a wide variety of processing units and with the flexibility to process shale oil by several unit configurations. Unfortunately, most of the refineries which are typical of the Rocky Mountain States are relatively simple and will at best have one way in which to process shale oil. In the following discussion, descriptions of the major refining processes which can be used in shale oil refining are presented along with representative operating conditions when processing shale oil. Any given refinery will have several--if not all--of the processing units. This discussion will provide a basis to estimate the ability of a refinery to process shale oil.

Hydrotreating

Hydrotreaters will play a major role in shale oil refining because they provide the means to remove the sulfur, nitrogen, and oxygen as well as arsenic. This is done in a hydrotreating unit such as that shown in the general schematic diagram of Figure D-2. The general flow schemes of naphtha, kerosene, or gas oils hydrotreaters are similar. The feedstock is mixed with hydrogen, either before or after preheating, and passed through a guard reactor (not shown) which removes arsenic and iron, and prevents poisoning of the downstream hydrotreating catalyst. Most hydrotreating reactions are carried out below 800°F to minimize cracking, and the feed is usually heated to between 500°F and 800°F.

The reactor normally contains a fixed bed of catalyst pellets impregnated with nickel, cobalt, molybdenum, or tungsten or combinations of these elements. Units which process heavy oil or resid often utilize an ebullated rather than a fixed bed of catalyst. In the presence of the hydrogen and catalyst, nitrogen, sulfur, and oxygen are converted to ammonia, hydrogen sulfide, and water, respectively. In addition, aromatics and olefins are saturated. Some conversion of heavy materials to lighter components also occurs. The degree to which these reactions proceed depends upon the conditions employed. The hydrotreater also provides facilities for recycling unused hydrogen back to the reactor, removal of the hydrogen sulfide, ammonia, and water by-products, and fractionation to produce the desired boiling range products.

The hydrogen which is consumed in the hydrotreater must either be supplied from other units in the refinery which produce by-product hydrogen, or a stand-alone hydrogen generation unit must be built. Many refineries operate with a balance between by-product hydrogen production and the consumption of hydrogen in hydrotreaters. If a change in feedstock is made, such as adding shale oil to the crude slate, the plant hydrogen balance may be significantly altered because of the greater hydrogen consumption required for shale oil hydrotreating.

Naphtha Hydrotreating

If high octane gasoline is to be produced from shale oil naphtha, the nitrogen content of the naphtha must be reduced to about 0.5 ppm or less in a naphtha hydrotreater. Higher nitrogen concentrations will lead to deactivation of the catalytic reforming unit catalyst. Literature references to the conditions required for shale naphtha hydrotreating are generally limited to cases in which a blend of naphtha from coking and straight run naphtha is processed. Operating conditions reported sufficient to produce 1.5 ppm product nitrogen are 1,500 psig, 700°F, and 1.0 LHSV (liquid hourly space velocity). (The hydrogen consumption reported for these conditions was 627 standard cubic feet per barrel, which reflects a high hydrogen requirement to saturate the large concentrations of olefins produced during coking. Actual hydrogen consumption for a straight run naphtha would be considerably lower and is of little economic consequence if the naphtha is subsequently processed in a catalytic reformer. Under these circumstances, hydrogen consumed during denitrogenation is subsequently recovered from the reformer.) However, it should be noted that the small volume of straight run naphtha available from raw shale oil fractionation would probably be blended with other naphtha streams in the refinery.

The hydrotreated naphtha could be blended to naphthenic type JP-4 military jet fuel, or undergo further processing to produce gasoline stocks.

Distillate Hydrotreating

The shale oil fractions boiling between about 380°F to 530°F are suitable components for jet fuel, diesel fuel, and fuel oil. The use of shale oil to produce jet fuels and marine diesel fuel has been of considerable interest, due in part because the Department of Defense would like to have a secure supply of military fuel for reasons of national security.

The characteristics and specifications required for an acceptable jet fuel is highlighted in the following:

- Low hydrogen contents of jet fuels have been correlated with increased soot and smoke emissions. In addition to being an environmental problem, smoke emissions increase the vulnerability of military aircraft. The particulates in smoke are also responsible for the formation of a luminous flame which greatly increases the heat transfer by radiation to engine components.

- Jet fuel high in nitrogen content translates to increased nitrogen oxide emissions. In addition, a relationship between the tendency for increased gum formation and poor storage/thermal stability with increased nitrogen content has been observed.

- Olefinic content is important because the olefins are precursors of gum, which degrade thermal and storage stability.

- Aromatics, in addition to having a low hydrogen content and resulting smoke formation problems, cause elastomeric O-rings in fuel systems to swell. If aromatic concentrations are too high, swelling is excessive and the O-ring can expand out of its cavity. If aromatics are too low, swelling is not sufficient to effect a seal, and leakage occurs.

Under contract with the Air Force, Exxon has evaluated the hydrotreating conditions necessary to produce suitable jet fuels from shale oil distillate. Their laboratory work showed that acceptable jet fuels can be produced with nickel-molybdenum catalysts under moderately severe hydrotreating conditions of 700°F, 4,000 standard cubic feet per barrel treat gas rates, 1,200 psig, and one LHSV. Hydrogen consumption was approximately 1,050 standard cubic feet per barrel. Under these conditions, the sulfur content of Paraho-derived shale oil was reduced from 0.74 weight percent to less than 10 ppm. Nitrogen content was reduced from 1.16 weight percent to 5 ppm at the start of operations, and 40 to 100 ppm after a thirty-day run. (This decrease in nitrogen removal was caused by slow deactivation of the nickel-molybdenum catalyst for denitrogenation.)

From a refining standpoint, shale oil is a very good alternate feedstock for jet fuel type transportation fuels. One of its major drawbacks is that the volume of material boiling in the jet fuel range is limited.

If shale oil distillate is to be blended into fuel oil, the product specifications are significantly reduced and the distillate shale oil hydrotreater could operate under much less severe conditions.

Gas Oil Hydrotreating

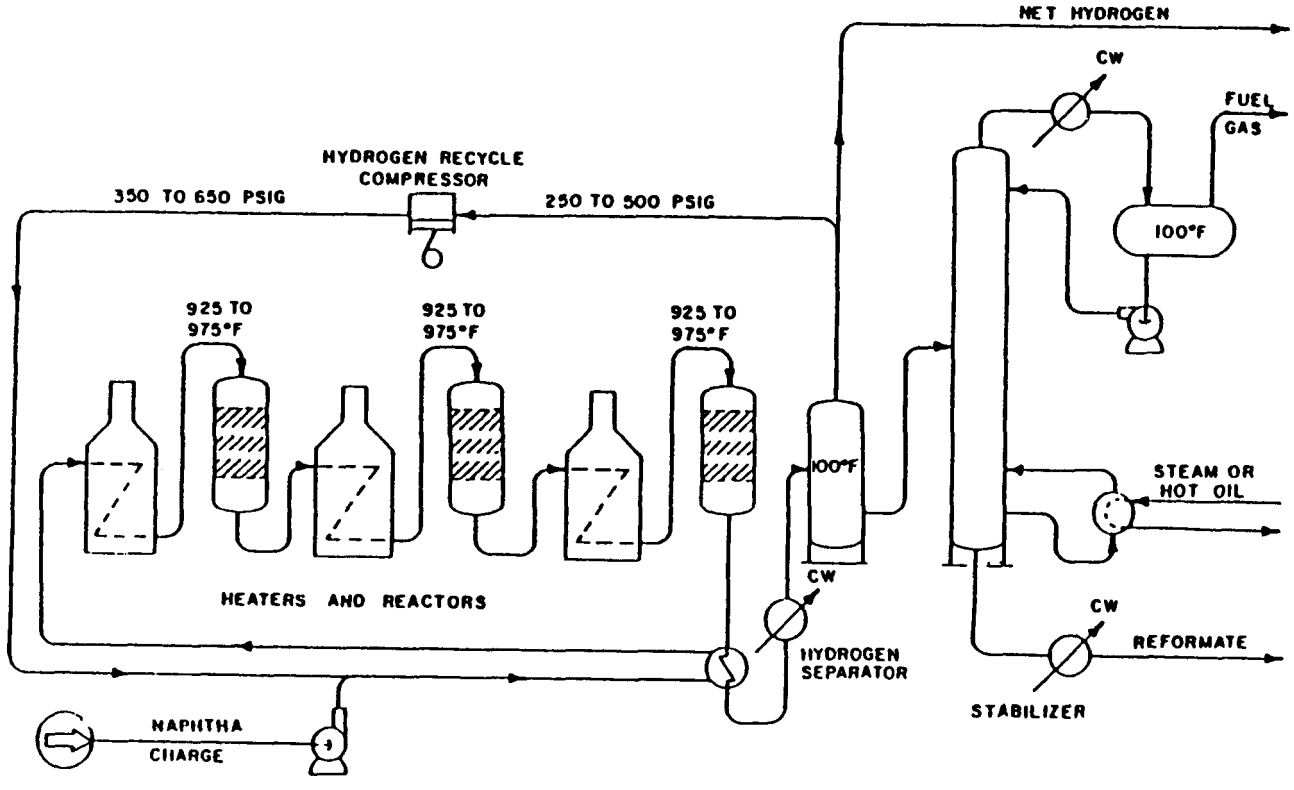
The atmospheric and vacuum gas oils are blended in fuel oils or--depending on the refinery processing units available--are converted to lighter fuels in a hydrocracking or Fluid Catalytic Cracking Unit. The amount of shale gas oil which could be blended into fuel oil would depend both on the size of the existing market for fuel oil and on the pour point of the fuel oil blend. Fuel oil based entirely on shale oil components would face potentially high nitrogen oxide emissions if substantial denitrogenation was not accomplished. The probable worst case requirement for gas oil denitrogenation is based on providing a suitable feed to a FCCU. Since nitrogen compounds act to temporarily deactivate cracking catalysts, the maximum nitrogen content for subsequent catalytic cracking would be about 3,000 ppm. The operating conditions required to denitrogenate atmospheric and vacuum gas oils would be similar to those required for whole shale oil hydrotreating. Reactor conditions of 745°F, 1,850 psia hydrogen partial pressure (2,200 psig total pressure), 0.6 LHSV, and a gas treat rate of 5,000 standard cubic feet per barrel have been shown by Chevron to produce a hydrotreated gas oil nitrogen concentration of approximately 1,000 ppm. These tests were made on whole shale oil; a hydrogen consumption for the gas oil fraction alone was not available. Under these severe conditions, some hydrocracking of the shale oil fraction occurs.

Raw Shale Oil Hydrotreating

The technology which has been developed in residuum hydrodesulfurization makes it possible to hydrotreat whole shale oil without a prior fractionation step. This approach has been taken both on the laboratory scale, and in a 73 thousand barrel refining test done by Sohio for the United States Navy. It is technically possible to increase the severity of this initial hydrotreating process to the point where the product oil contains one ppm of nitrogen. However, as discussed previously, a more reasonable approach seems to be to hydrotreat to about a 1,500 ppm nitrogen product level to accommodate downstream processing catalyst deactivation requirements.

FIGURE D-3

GENERALIZED CATALYTIC REFORMING SCHEMATIC DIAGRAM



In laboratory tests, Chevron has hydrotreated whole Paraho shale oil at 745°F, 2,200 psig total pressure (1,850 psia hydrogen partial pressure), 0.6 LHSV, 5,000 standard cubic feet per barrel recycle gas rate, with a nickel-tungsten catalyst to produce a 500 ppm nitrogen product. The gross hydrogen consumption was about 2,000 standard cubic feet per barrel. Union Oil has also reported on the product yields from hydrotreating whole shale oil produced in a Union retort. Although the reactor conditions were not specified, the hydrogen consumption was given as 1,500 standard cubic feet per barrel, and an indicated catalyst life of 1.5 years is expected.

Catalytic Reforming

If motor gasoline is to be produced from shale oil naphtha, a catalytic reforming unit would be used to increase the octane rating. The unleaded octane rating of hydrotreated shale oil naphthas range between 30 and 50. The catalytic reforming unit typically utilizes a platinum-impregnated catalyst to convert low octane components into high octane components with a net production of hydrogen. Figure D-3 is a schematic diagram of UOP's Platforming process, which is illustrative of catalytic reforming technology.

The pretreated feed and recycle hydrogen are heated to 925°F to 975°F before entering the first reactor. In the first reactor, the major reaction is the dehydrogenation of naphthenes to aromatics and--since this is strongly endothermic--a large drop in temperature occurs. To maintain the reaction rate, the gases are reheated before being passed over the catalyst in the second reactor. As the charge proceeds through the reactors, the reaction rates decrease, the reactors become larger, and the reheat needed lessens. Three reactors are usually sufficient to provide the desired degree of reaction, and heaters are needed before each reactor to bring the mixture up to reaction temperature. In practice, either separate heaters can be used or one heater can contain several separate coils. The reaction mixture from the last reactor is cooled and the liquid products condensed. The hydrogen-rich gases are separated from the liquid phase in a drum separator and the liquid from the separator is sent to a fractionator to be debutanized.

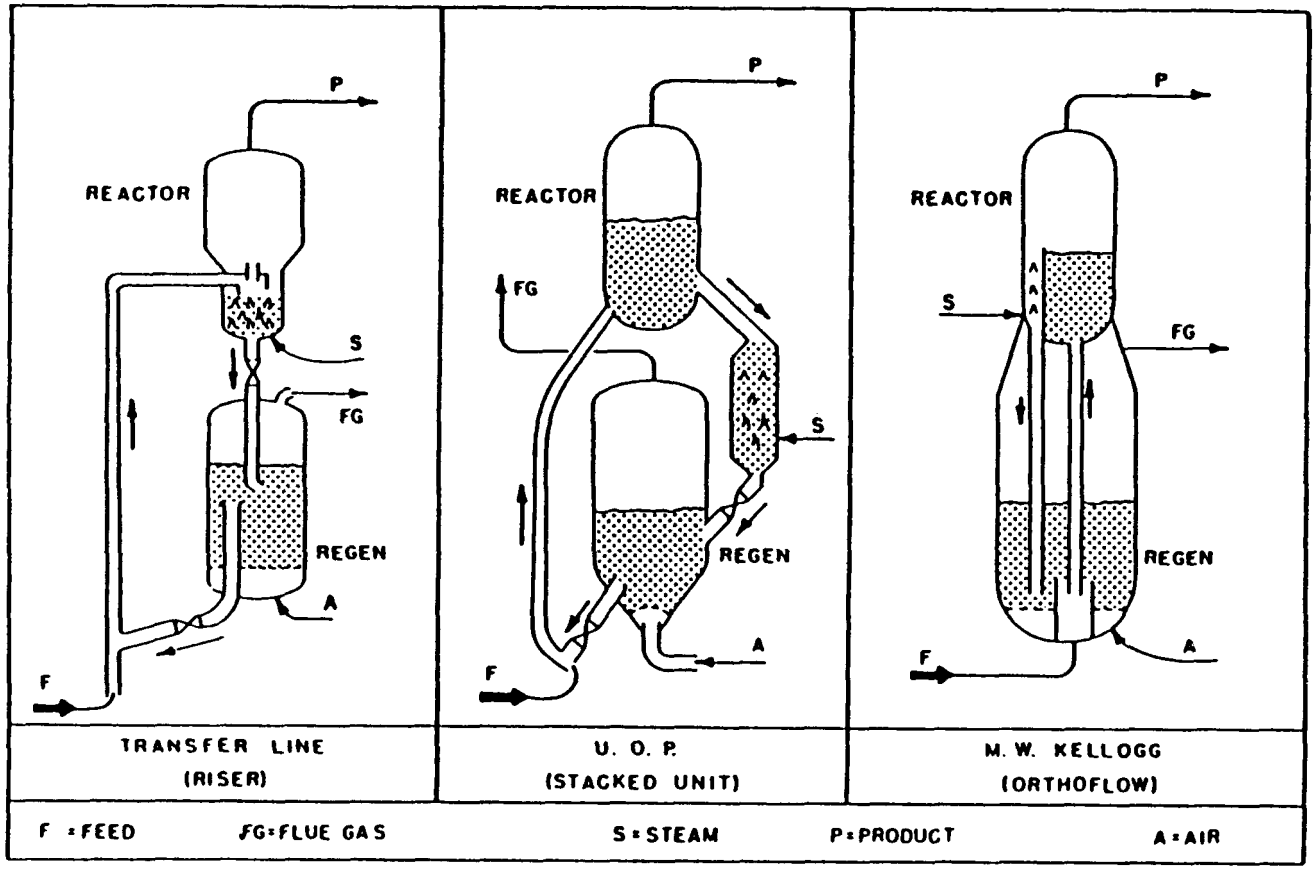
The hydrogen-rich gas stream is split into a hydrogen recycle stream and a net hydrogen by-product which is used in hydrotreating or hydrocracking operations, or as fuel.

From a refinery standpoint, operation of a catalytic reforming unit on hydrotreated shale oil naphthas should not require specialized equipment or operating procedures because virtually all of shale oil's troublesome components have been removed during hydrotreating. Laboratory tests have been conducted on catalytic reforming of shale oil naphtha which show that at 908°F, 2.95 LHSV and 500 psig operating conditions, a 90.0 octane gasoline (RON, clear; 82.4 MON, clear) can be produced with a C_4^+ volume yield of 83.8 percent. The net hydrogen production was 931 standard cubic feet per barrel.

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FIGURE D-4

FLUID CATALYTIC CRACKING UNIT CONFIGURATION



Fluid Catalytic Cracking

The Fluid Catalytic Cracking (FCC) process is widely used to convert heavy oils into more valuable gasoline and light products. Several types of FCC Units are in use, and Figure D-4 shows simplified flow diagrams of three process configurations.

The process employs a catalyst in the form of very fine particles which behave as a fluid when aerated with a vapor. The fluidized catalyst is circulated continuously between the reaction zone and the regeneration zone, and acts as a vehicle to transfer heat from the regenerator to the oil feed and reactor. Average reactor temperatures are in the range of 870°F to 950°F, with oil feed preheat temperatures from 600°F to 850°F, and regenerator temperatures from 1,100°F to 1,300°F. Newer units are designed to take advantage of high activity zeolite catalysts which allow nearly all of the cracking reactions to take place in the riser which transports the catalyst/oil mixture to the reactor.

Control over the product slate is obtained by varying reactor temperature, the catalyst/oil ratio, and catalyst activity. This unit is very important in providing a refiner with the flexibility to produce a wide variety of products depending on seasonal and market conditions.

Hydrotreated shale gas oil is a desirable feedstock for Fluid Catalytic Cracking because naphthenic and paraffinic materials (such as shale oil) are much more readily cracked than aromatic materials. The amount of carbon or coke which is deposited on the cracking catalyst also varies significantly with different types of feedstocks. Hydrotreated shale oil produces appreciably lower coke yields than hydrotreated Arabian gas oils at constant conversion and at similar feed nitrogen levels.

Chevron's experience in the catalytic cracking of hydrotreated shale oil and hydrotreated Arabian gas oil was as follows:

- At 930°F reactor temperature, hydrotreated Paraho shale oil with 1,300 ppm nitrogen was cracked to about the same conversion as the Arabian gas oil with 320 ppm nitrogen when the two stocks were cracked at constant severity.

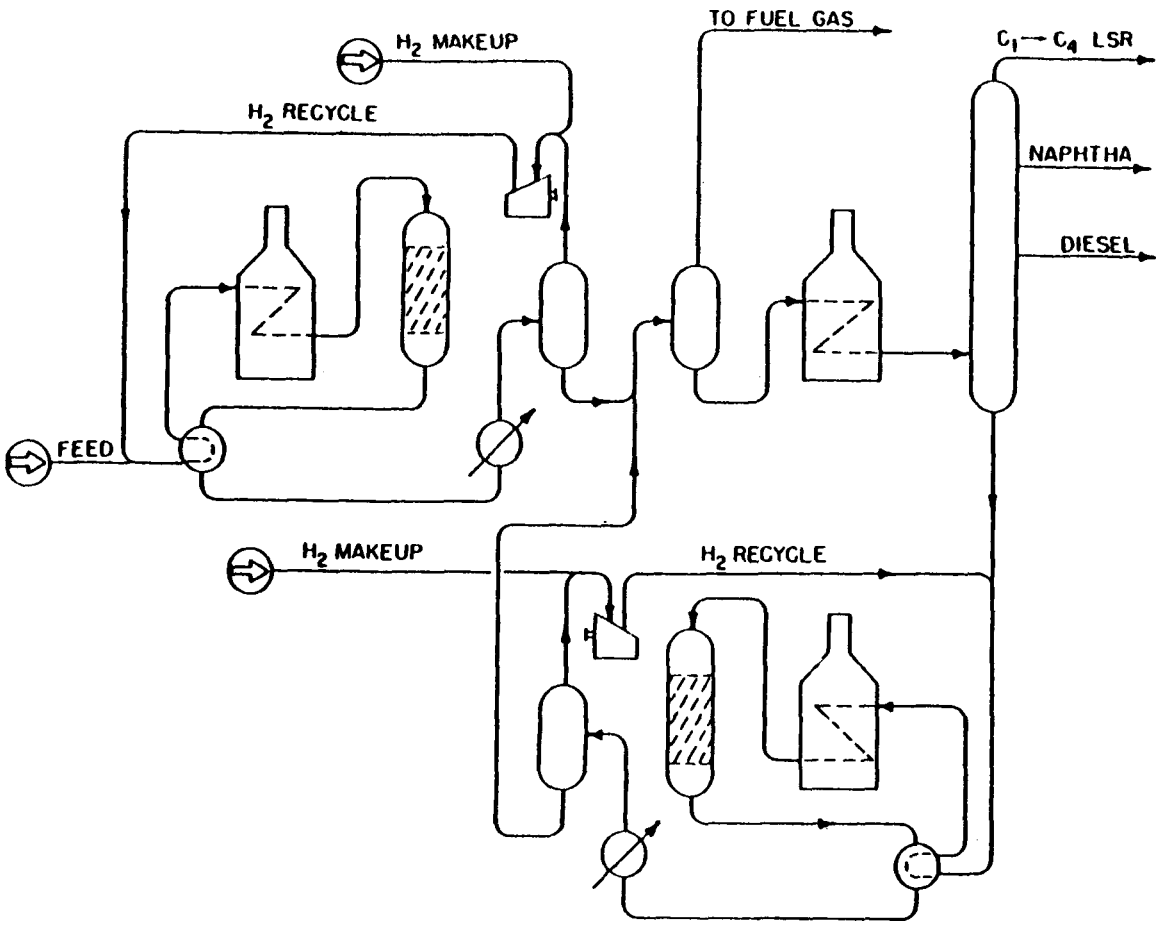
- Coke yields for the shale oil are appreciably lower than those for the Arabian gas oil with 860 ppm nitrogen at reactor temperatures of 930°F and 975°F. The coke yields were the same at 975°F as when compared with a lower nitrogen Arabian gas oil (320 ppm nitrogen).

- Gasoline yields (C_5s/430°F) for 1,300 ppm nitrogen shale oil are intermediate to those obtained for the 320 and 860 ppm nitrogen Arabian gas oils at 930°F. At 975°F, the shale oil gasoline yields were equal to those of the 320 ppm nitrogen Arabian gas oil.

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FIGURE D-5

GENERALIZED TWO-STAGE HYDROCRACKING SCHEMATIC DIAGRAM



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- The gasolines and cycle oils have properties which are similar to those obtained from petroleum gas oils.

In conclusion, the use of the Fluid Catalytic Cracking process to produce a variety of light fuels from heavy shale oil fractions represents an attractive refining process to utilize shale oil.

Hydrocracking

The catalytic hydrocracking process performs a refining function which is similar to that of the Fluid Catalytic Cracking process--it converts low value, heavy fractions to gasoline, jet fuels, and light fuel oil. By changing catalysts, processing conditions, and equipment configurations, the hydrocracking process can utilize distillate or residual feedstocks and can also provide a great deal of product slate flexibility to accommodate changing market conditions.

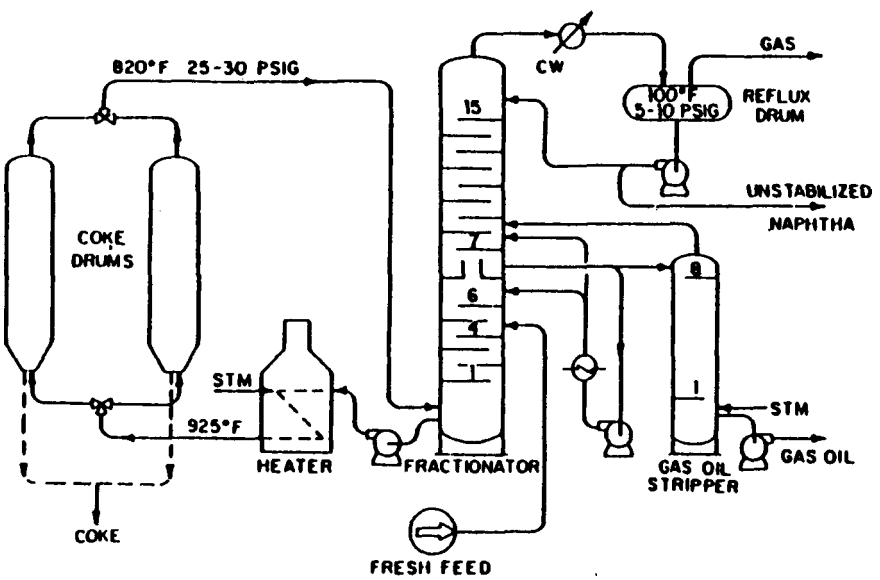
Shale oil might be processed in either a single stage or two-stage system. In a single stage system, the process flow is the same as for the second stage of a two-stage plant. Because hydrocracking catalyst is susceptible to poisoning by metallic salts, organic nitrogen, oxygen and sulfur compounds in the feedstock, the feed must be hydrotreated to remove these contaminants before hydrocracking. In a two-stage system, the first stage essentially acts to remove additional nitrogen from the feedstock.

A schematic diagram of a two-stage hydrocracker is shown in Figure D-5. The fresh feed is mixed with makeup hydrogen and recycle gas (high in hydrogen content) and passed through a heater to the first reactor. The reactor effluent goes through heat exchangers to a high pressure separator where the hydrogen-rich gases are separated and recycled to the first stage for mixing both makeup hydrogen and fresh feed. The liquid product from the separator is sent to a distillation column where the gasoline and lighter fractions are taken overhead and the bottoms used as feed to the second stage reactor. If jet fuel or diesel fuel is one of the products desired, the distillation column separation is made with the jet fuel or diesel fuel going overhead. The bottoms from the distillation column are mixed with recycle hydrogen and sent through a furnace to the second stage reactor. In the second stage reactor the temperature is maintained to bring the total conversion of the unconverted oil from the first stage and second stage recycle to 50 to 70 volume percent per pass. The second stage product is combined with the first stage product prior to fractionation.

Chevron has evaluated the single stage pilot plant hydrocracking of both a 650°+F shale gas oil stream and a 625/850°F shale oil stream. The nitrogen content of both feeds was about 530 ppm. Operating conditions for the

FIGURE D-6

GENERALIZED DELAYED COKING SCHEMATIC DIAGRAM



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625/850°F feedstock runs were 790°F reactor temperature, 1.0 LHSV, 2,150 psia hydrogen partial pressure (2,350 psig total pressure), 8,000 standard cubic feet per barrel recycle gas rate, and a recycle cut point of 550°F. The recycle oil stream was cracked to extinction. A 53 percent, 535°F conversion per pass was obtained with a chemical hydrogen consumption of about 1,250 standard cubic feet per barrel. The yields of C_5/180°F, 180/300°F, and 300/535°F products were approximately 14, 27, and 68 volume percent, respectively. This illustrates the potentially high yields of jet fuel components (300/535°F) which can be produced by shale oil hydrocracking.

Coking

Coking has been widely considered as a means for both partial upgrading of whole shale oil to produce a pipelineable material, and as a refining process to convert high boiling shale oil fractions to lighter materials. The delayed coking process was developed to minimize refinery yields of residual fuel oil by severe thermal cracking of high boiling stocks.

A schematic diagram of a delayed coking unit is shown in Figure D-6. Hot fresh feed is charged to the fractionator two to four trays above the bottom vapor zone. This quenches the vapor from the coke drums and preheats the fresh feed. Unvaporized fresh feed and condensed recycle are pumped from the bottom of the fractionator through the coker heater where it is partially vaporized, and then moved into one of two coke drums. The unvaporized portion of the heater effluent settles out in the coke drum where the combined effect of retention time and temperature causes the formation of coke. Vapors from the top of the coke drum return to the base of the fractionator. These vapors consist of steam and the products of the thermal cracking reaction--gas, naphtha, and gas oils.

When the coke drum in service is filled to a safe margin from the top, the heater effluent is switched to the empty coke drum and the full drum is isolated, steamed to remove hydrocarbon vapors, cooled by filling with water, opened, drained, and the coke removed.

The amount of coke formed during shale oil coking is dependent on the end boiling point of the coker distillate. As the coker distillate end point increases, less of the feedstock is converted to coke. Chevron found that when coking whole Paraho shale oil the amount of feed converted to coke was linear with the coker distillate end point. At 850°F end point, the coke yield was 7 weight percent. An end point of 650°F produced a coke yield of 22 percent. Delayed coking runs by Sohio on a 700°+F Paraho shale oil fraction produced a coke yield in relatively good agreement with the Chevron results.

TABLE D-3

PROPERTY IMPROVEMENT RESULTING FROM DELAYED COKING OF RAW SHALE OIL

Type	Raw Shale Oil	Shale Oil Coker Distillate
Inspections		
Gravity (°API)	20.50	32.70
Sulfur (Wt. %)	0.63	0.61
Total Nitrogen (Wt. %)	2.15	1.75
Oxygen (Wt. %)	1.19	0.94
Arsenic (ppm)	26.50	6.30
Pour Point (ASTM, °F)	85	25
Iron (ppm)	68.00	0.40

Delayed coking concentrates the nitrogen, arsenic, iron, and ash in the coke. The changes in concentration of these components between whole shale oil and coke are indicated as follows:

	Shale Oil Feed	Coke
Nitrogen (Weight Percent)	2.15	4.08
Arsenic (ppm)	27	190
Iron (ppm)	68	100
Ash (Weight Percent)	0.04	0.38

As would be expected, the coker distillate represents an improved feedstock for further refining because the coking operation has removed very heavy components and a significant portion of the contaminants. This improvement in quality is apparent from Table D-3 for coking of whole Paraho shale oil.

The major disadvantage of delayed coking in a refining system is that the yield of liquid products from a given volume of feed material is significantly reduced. Also, the high nitrogen coke is likely to have a low market value.

REFINING LOGISTICS

Existing Refining Capabilities

Shale oil production will reduce our dependence on foreign oil. What area or areas can most benefit and best utilize this resource is a key question. The two major factors to this issue are:

- Regional crude oil supply position
- Area processing capabilities.

Pace's forecast of crude oil runs to stills by region is provided in Table D-4. Curtailment of Canadian crude oil imports has had a particular impact on PADDs 2A and 2B. Shale oil could aid refineries in Montana and Wyoming that have been hardest hit by the reduction in Canadian imports and the decline in local production.

The area composed of PADDs 2B and 4 is a net importer of products—primarily from PADD 3. New refinery capacity based on shale oil would reduce these product movements.

Raw shale oil will require large volumes of hydrogen for hydrotreating. The amount of hydrogen required is estimated at about 2,000 standard cubic feet per barrel of raw shale oil. A review of each of the 264 refineries located in PADDs 2A, 2B, 3, 4, and 5 was conducted to determine:

- If existing facilities have processing units required to refine shale oil to desirable end products
- Which refineries have a surplus hydrogen above that required by existing refinery units
- Shale oil refining capacity based on estimated hydrogen balances.

Shale oil refining capability was determined based on whether a refinery had catalytic reforming, catalytic hydrorefining, and/or catalytic hydrotreating units. Those refineries which did not have such units were eliminated. Hydrogen balances for refineries with shale oil capability were estimated by adding hydrogen production from catalytic reformers and hydrogen generators, and subtracting hydrogen demand by catalytic hydrotreating, catalytic hydrorefining, and hydro cracking units.

Raw shale oil refining capacity was determined by dividing the daily surplus hydrogen by the hydrogen demand of raw shale oil (2,000 standard cubic feet per barrel of crude oil). Table D-5 lists those refineries in PADDs 2A, 2B, 3, 4, and 5 with raw shale oil capacities of 10,000 barrels per day or more, and shows the estimated hydrogen surplus. Based on the estimated hydrogen surplus, the refineries with a shale oil capacity of 10 thousand barrels per day or more could refine nearly 760 thousand barrels per day of raw shale oil. However, it would be incorrect to conclude that ample hydrogen will be available for raw shale oil processing. As noted previously, there will be a significant decline in the quality of the overall crude oil supply available to United States refiners. Therefore, hydrogen consumption will increase due to the additional processing required to adjust to overall crude oil slate quality shifts.

No refinery within the five PADDs reviewed has the hydrogen surplus to refine raw shale oil at a rate of 50 thousand barrels per day or more (a level generally considered to be the output of a single commercial oil shale facility). PADD 5 has the highest per refinery raw shale oil capacity, but excess Alaskan North Slope crude oil has been lowering this potential. The low per refinery raw shale oil capacity will require the distribution of projected shale oil production by 1990 and 2000 to numerous refineries.

The refineries listed in Table D-5 appear capable of processing shale oil when hydrogen availability is the only variable considered. Two process considerations are also critical to a refiner's capability to handle shale oil:

- Equipment design
- Hydrogen purity.

TABLE D-4

UNITED STATES REFINERY CRUDE OIL RUNS
(Thousand Barrels Per Day)

	PAD District					
	1	2A	3	2B/4	5	Total U.S.
1985						
Domestic	147	948	2,994	991	1,883	6,963
Syncrude	-	12	-	24	-	36
Foreign						
Canada	-	-	-	160	-	160
Other	1,549	1,382	3,105	416	228	6,689
Subtotal	1,549	1,382	3,105	576	228	6,839
Total	1,696	2,342	6,100	1,591	2,111	13,838
1990						
Domestic	186	1,084	2,705	833	1,998	6,806
Syncrude	-	250	-	100	-	350
Foreign						
Canada	-	-	-	160	-	160
Other	1,221	977	3,415	510	120	6,243
Subtotal	1,221	1,977	3,415	670	120	6,391
Total	1,407	2,311	6,120	1,603	2,118	13,559
2000						
Domestic	170	1,000	3,180	1,050	2,000	7,400
Syncrude	-	500	600	100	-	1,200
Foreign						
Canada	-	-	-	160	-	160
Other	1,590	900	2,544	330	180	5,520
Subtotal	1,590	900	2,520	490	180	5,680
Total	1,760	2,400	6,300	1,640	2,180	14,280

TABLE D-5

REFINERIES POTENTIALLY CAPABLE OF REFINING RAW SHALE OIL VOLUMES OF 10,000 BARRELS PER DAY OR MORE WITHOUT REQUIRING ADDITIONAL HYDROGEN PRODUCTION

Refinery/Location	Surplus[1] Hydrogen (MMSCFD)	Potential[2] Shale Oil Capacity (BPD)
PADD 2A		
Marathon Oil/Robinson, Illinois	40	20,000
Mobil Oil/Joliet, Illinois	26	13,000
Shell Oil/Wood River, Illinois	50	25,000
Texaco/Lawrenceville, Illinois	22	11,000
Amoco Oil/Whiting, Indiana	50	25,000
Ashland Petroleum/Catlettsburg, Kentucky	33	16,500
Sun Oil/Toledo, Ohio	53	26,500
Total	274	137,000
PADD 2B		
Getty Oil/Eldorado, Kansas	22	11,000
Mobil Oil/Augusta, Kansas	25	12,500
Continental Oil/Ponca City, Oklahoma	30	15,000
Texaco/Tulsa, Oklahoma	20	10,000
Total	97	48,500
PADD 3		
Amoco Oil/Texas City, Texas	56	23,000
Arco/Houston, Texas	39	19,500
Chevron/El Paso, Texas	20	10,000
Crown Central Petroleum/Houston, Texas	23	11,500
Exxon/Baytown, Texas	31	15,500
Gulf Oil/Port Arthur, Texas	46	23,000
Mobil Oil/Beaumont, Texas	75	37,500
Phillips Petroleum/Borger, Texas	20	10,000
Phillips Petroleum/Sweeny, Texas	33	16,500
Southwestern Refining/Corpus Christi, Texas	25	12,500
Sun Oil/Corpus Christi, Texas	27	31,500
Union Oil of California/Beaumont, Texas	34	17,000
Cities Service/Lake Charles, Louisiana	33	16,500
Exxon/Baton Rouge, Louisiana	36	18,000
Gulf Oil/Belle Chasse, Louisiana	28	14,000
Texaco/Convent, Louisiana	25	12,500
Chevron USA/Pascagoula, Mississippi	44	22,000
Total	595	297,500

.....continued

Table D-5 (continued)

Refinery/Location	Surplus[1] Hydrogen (MMSCFD)	Potential[2] Shale Oil Capacity (BPD)
PADD 4		
None		
PADD 5		
Arco/Carson, California	49	24,500
Chevron/El Segundo, California	95	47,500
Chevron/Richmond, California	25	12,500
Exxon/Benicia, California	81	40,500
Mobil Oil/Torrance, California	51	25,500
Texaco/Wilmington, Caliofrnia	49	24,500
Tosco Corporation/Martinez, California	61	30,500
Union Oil/Los Angeles, California	56	28,000
Union Oil/Rodeo, California	44	22,000
Arco/Cherry Point, Washington	42	21,000
Total	553	276,500

Notes: Refineries only include those with catalytic reforming and catalytic hydrotreating/catalytic hydrorefining units.

1. Approximate hydrogen surplus based on estimated plant hydrogen balance.

2. Capacity of refining raw shale oil which is estimated to require 2,000 standard cubic feet of hydrogen per barrel of crude oil to remove excess nitrogen and sulfur.

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Shale oil denitrogenation requires high pressure operation of hydroprocessing facilities which are nearer to hydrocracking requirements than conventional hydrotreating requirements. In our survey of refineries with hydroprocessing facilities it was not possible to determine if existing equipment could operate under sufficiently severe conditions to denitrogenate shale oil. Also, in many cases the excess hydrogen produced by catalytic reformers might not be of high enough purity to meet hydroprocessing requirements. This occurs because the pressure required for denitrogenation is based on hydrogen partial pressure. If the available excess hydrogen is of low purity, the total hydroprocessing pressure must be increased to satisfy the hydrogen partial pressure requirements. This could in turn cause the total pressure requirement to exceed the pressure rating of existing equipment.

SHALE OIL DISTRIBUTION

As the production of shale oil increases with the startup of additional projects, the pipeline transportation system will have to be expanded to transport raw shale oil to distant refining centers, or to transport refined products to demand centers. The transportation system will be a critical factor in the ultimate usage of shale oil.

Shale oil development has focused on the logistics and technology of mining and processing. When commercial projects get underway, existing pipelines will quickly reach their design capacity, and expansion or new pipeline construction will be required. Shale oil's high pour point will require special considerations for existing or new pipelines. The use of existing petroleum pipelines will require either an upgraded shale oil or syncrude, or use of flow improving additives. New shale oil pipelines can be designed to accommodate shale oil's high pour point.

Since pipeline transportation will be critical to shale oil's orderly development, we have briefly examined the constraints and requirements of both flow improving additives (pour point depressants in existing pipelines) and new shale oil-dedicated pipelines.

Flow Improving Additives

The use of chemical additives to modify flow properties of waxy crude oils is very much an art rather than a science. Each particular system or feedstock must be tested with the candidate flow improving additives because of the inability to translate results between different systems or feedstocks. Many companies have made extensive efforts to develop additives, which by modifying the wax crystal structure result in a market change in the flow properties. In general, these additives can seldom be justified due to the high cost of the

treatment compared with the alternative of a good pipeline system design. However, there are a number of situations in which the use of these additives can be justified:

- Injection of an additive prior to a scheduled shutdown so as to avoid the use of flushing oil.
- Addition to the oil during a difficult restart operation when the system may remain cold until flow is fully established.
- Transportation of an oil with flow characteristics more severe than those for which the system was originally designed.
- Transportation of crude oil in an existing buried, uninsulated, conventional crude oil pipeline.

Additives also reduce the thixotropic effects (the tendency of a gel to liquefy under vibration, and solidify at rest) of the fluid.

In designing a pipeline system it costs very little to make provisions for the injection of an additive for use in the above listed situations. For satisfactory results, it is desirable to ensure that all the wax is brought into solution prior to additive treatment. This usually entails heating to 90°F to 130°F.

The use of flow characteristics improvers currently appears to be limited by the availability of excess capacity in existing pipeline systems which could be devoted to shale oil transport.

Existing Pipeline Systems

Two existing crude oil pipeline systems have the potential to transport raw or upgraded shale oil. The northern system and the southern system are shown in Figure D-7. The ability of both systems to handle projected shale oil production is dependent on conventional oil production levels and the distribution scheme for Alaskan North Slope oil in the area. Both systems would require construction of connecting lines to connect with Piceance Creek oil shale facilities and expansions to increase available capacity. A discription of the two existing crude oil pipeline systems follows.

Northern System

The northern system was developed to move crude oil from the states of Montana, Wyoming, Colorado, and Utah to refineries located in those states, and to export crude oil production in excess of refining capacity to PADDs 2A and 2B. Canadian crude oil has been transported via the system into PADDs 2A and 2B. Curtailment of Canadian imports has in some cases increased available capacity in the system.

Chevron

Chevron Oil Company operates a crude oil pipeline that originates at Rangley, Colorado and terminates at Salt Lake City, Utah. The line consists of two 10-inch pipelines, each 160 miles long with a capacity of 105 thousand barrels per day and a throughput of 100 thousand barrels per day. Although existing available capacity is relatively small, declining domestic crude oil production and/or expansion of the line could increase available capacity significantly.

Amoco

Amoco pipelines originate at Rangley, Colorado (10-inch) and near Craig, Colorado (8-inch). The 10-inch line connects with another 8-inch line which crosses southern Wyoming and connects Salt Lake City, Utah with Fort Laramie, Wyoming. The Fort Laramie terminus includes a connection with the major 20-inch Amoco line from Elk Basin, Wyoming to Freeman, Missouri.

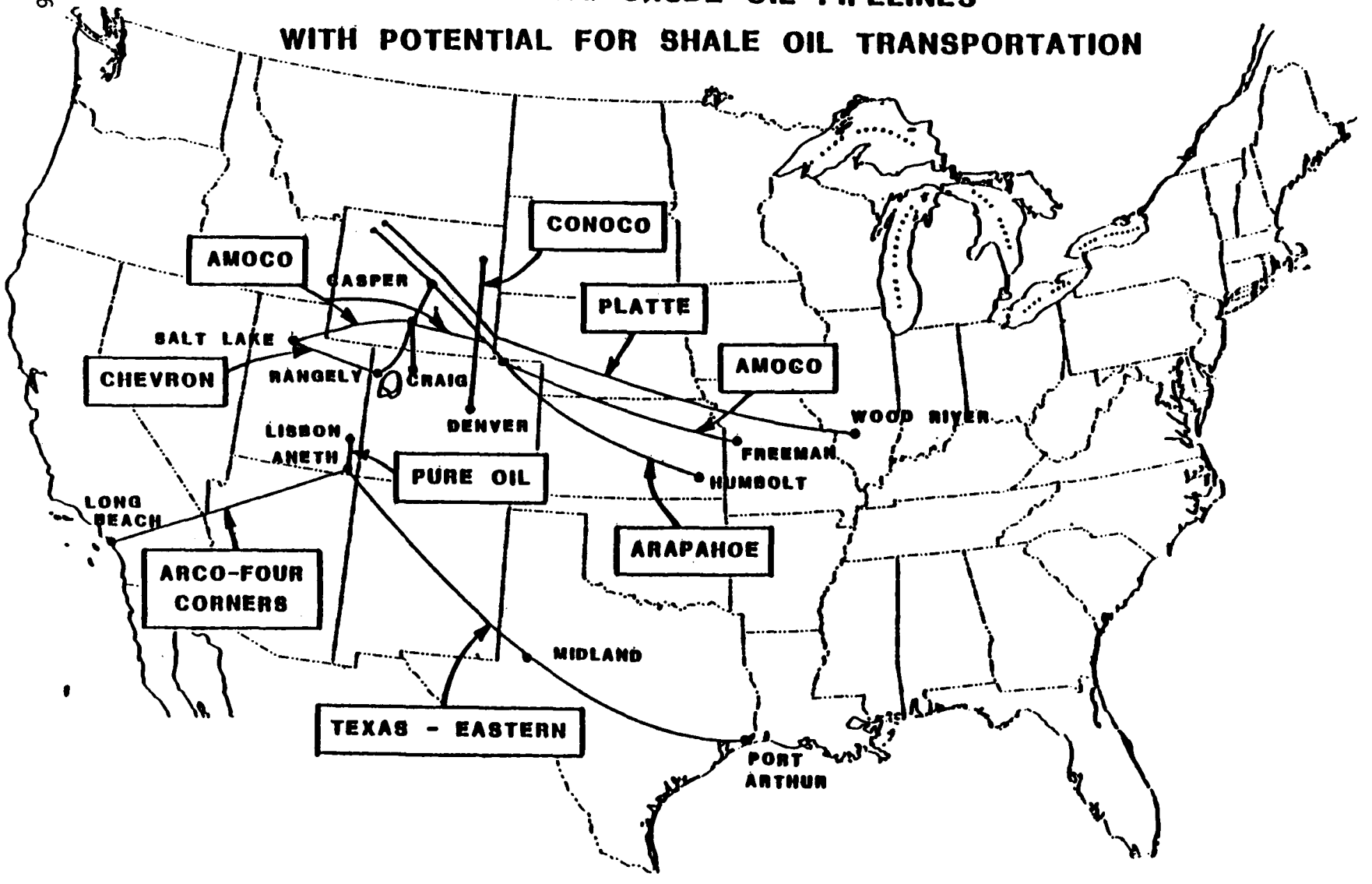
The 8-inch line from Craig, Colorado crosses the southern Amoco line and terminates near the Amoco line in Casper, Wyoming. The Amoco line across southern Wyoming is operating at capacity to Salt Lake City (40 thousand barrels per day), and slightly below capacity to Fort Laramie, Wyoming (29 thousand barrels per day with 25 thousand barrels per day throughput). If this Amoco system in Wyoming and Colorado were expanded to handle large volumes of shale oil, it would provide access to several other pipeline systems which supply both major and minor refining centers. Possible tie-ins are listed in the following table.

Pipeline	Terminals	Excess Capacity (BPD)
Amoco (20-inch)	Elk Basin, Wyoming to Freeman, Missouri	45,000
Platte	Byron, Wyoming to Wood River, Illinois	120,000
Conoco	Gurnsey, Wyoming to Denver, Colorado	18,000
Arapahoe	Gurley, North Dakota to Humboldt, Kansas	100,000
	Total	283,000

Once the shale oil reaches the Midwest via the Amoco, Platte, or Arapahoe pipelines, other pipeline connections could transport the shale oil to refineries in PADDs 2A and 2B having the available processing facilities.

FIGURE D-7

EXISTING CRUDE OIL PIPELINES WITH POTENTIAL FOR SHALE OIL TRANSPORTATION



As noted, many of these alternatives may be affected by potential flow of Alaskan North Slope crude oil from the proposed Northern Tier pipeline. However, shale oil could supply the secondary market or southern markets of the proposed Northern Tier pipeline with about 280 thousand barrels per day through existing pipeline systems, allowing more of the Alaskan North Slope crude oil to be delivered in the northern portions of PADDs 2A and 2B. In addition, the Amoco system allows access to the refineries in Utah, Wyoming, and Montana which are currently running below capacity because of curtailment of Canadian imports and declining local production.

Southern System

The southern system (see Figure D-7) was developed to move crude oil from the Four Corners area to Long Beach, California and the Midland, Texas area. However, the western stretch from Long Beach to the Four Corners area is currently moving 28 thousand barrels per day of Alaskan North Slope crude oil from Long Beach to the Four Corners area. Due to the surplus of Alaskan North Slope crude oil on the West Coast, movement of shale oil in this system would be more logically to West Texas or the Gulf Coast.

Pure Oil Pipeline

The Pure Oil Pipeline originates in Lisbon, Utah and terminates at Aneth, Utah. The rated capacity is 50 thousand barrels per day and throughput is 35 thousand barrels per day. Construction of pipelines from the Piceance Creek basin to Lisbon, Utah and expansion of the Pure Oil Pipeline would allow shale oil to be transported to the south, where it could enter the Texas/New Mexico pipeline.

Texas/New Mexico Pipeline

This pipeline originates at Aneth, Utah and terminates at Port Arthur, Texas. The line has a capacity of 100 thousand barrels per day and a throughput of 80 thousand barrels per day. Expansion of this line would allow transportation of significant volumes of shale oil from the Pure Oil pipeline at Aneth to West Texas and the Gulf Coast. However, increased deliveries of Alaskan North Slope crude oil by way of the Arco Four Corners pipeline would decrease capacity available for shale oil.

It appears that existing crude oil pipeline systems have the potential to move about 300 thousand barrels per day of shale oil to the Gulf Coast and Midwestern refining centers. Utilization of this excess capacity will require major expansion or new construction of feeder lines from the oil shale region to

the Platte, Amoco, and Arapahoe lines to the north, and the Texas/New Mexico line to the south. Utilization of this available capacity is also dependent on the rate of decline of local conventional crude oil production and shipments of Alaskan North Slope crude oil from the proposed Northern Tier pipeline. Once shale oil production reaches 300 thousand barrels per day, major new pipelines will be required to handle any additional production.

However, in the short term, existing lines which originate in the shale oil region appear wholly inadequate to handle shale oil production levels in excess of 50 thousand barrels per day.

New Shale Oil Pipelines

There may be a considerable difference between the pour point of shale oil retorted by in situ or surface technologies. Evaluation of future new pipeline constraints is based on the conditions for high pour point surface—retorted shale oils.

We have made a rough estimate of the costs and requirements of a pipeline having a capacity of 40 to 180 thousand barrels per day. This size range was chosen because it provides flexibility for gradual increases in capacity which will be a requirement of a developing industry, yet will allow for reasonable economics of scale at full capacity.

The properties of the heavy crude oil are similar in general terms to shale oil as can be seen from the following table:

	Heavy Crude Oil	Raw Shale Oil
Gravity (°API)	25	19-24
Specific Gravity at 60°F	0.9024	0.934
Viscosity		
@ 100°F C.S.	17.0	18.0-31.0
@ 122°F C.S.	11.4	22.5
@ 210°F C.S.	4.0	5.1
Pour Point (°F)	95	85

The shale oil pipeline was assumed to start at Rifle, Colorado and to proceed via Kansas City to Chicago, serving a number of Midwestern refineries. The Rifle/Kansas City distance is about 750 miles, and Kansas City to Chicago is roughly 450 miles, giving a total distance of 1,200 miles. An 18-inch diameter pipeline was chosen which, at maximum capacity, would have a throughput of 140 thousand barrels per day at a maximum permissible design pressure of 1,200 psig. A ground temperature of 30°F at four feet depth was assumed.

At Rifle, the shale oil would be heated to 180°F and an appropriate number of reheating and pumping stations would be provided to ensure one of the following criteria:

- Increasing capacity to 140 thousand barrels per day to Kansas City, or
- Extending the pipeline to Chicago at a throughput (to Chicago) of 140 thousand barrels per day, with 180 thousand barrels per day in the Kansas City section as far as McPherson.

For all throughputs of between 40 and 140 thousand barrels per day to Kansas City, the initial heating and pumping station at Rifle would be required, followed by four pump booster and reheat stations to raise the oil temperature from 85°F to 180°F. The total cost of this sytem including rights-of-way, insulated line, five pump and heater stations, flow metering, instrumentation, and communication equipment, but excluding all tankage and breakout systems would be approximately $230 to $300 million. Link-up to heater stations would be designed for full throughput of 140 thousand barrels per day, but with provision for operation at the reduced throughput at 40 thousand barrels per day. Only a small reduction in investment for the initial operation at 40 thousand barrels per day is possible by omitting some of the booster pumps and drivers.

The extension of the pipeline to Chicago for a throughput of 140 thousand barrels per day would require the provision of three booster and heater stations which, together with the insulated pipeline and other facilities as described for the Kansas City section, would require an investment of a further $150 to $200 million. Operation of this section at 100 thousand barrels per day would be possible with 40 thousand barrels per day disposed of before Kansas City. A full 140 thousand barrels per day delivered to Chicago with a further 40 thousand barrels per day delivered as far as the concentration of refineries in the Wichita, El Dorado, Augusta/McPherson area would be possible to give a total offtake out of Rifle of 180 thousand barrels per day. This could be attained with the provision of two booster stations without heaters at an incremental cost of around $5 million.

The total cost of the shale oil-dedicated pipeline to Chicago is thus $400 to $500 million. Pipeline construction lead time is also a consideration. It should be noted that the upgraded shale oil pipeline proposed for the Colony Project (which would transport shale oil from Rifle, Colorado to Lisbon, Utah) required an Environmental Impact Statement which took over three years to complete.

One of the options open to Occidental would be to construct or participate in the construction of a spur line to connect the Piceance Creek region to Casper, Wyoming and tie into the Platte system to reach Wood River refining region. The announced possible production from the Piceance Basin could reach 250 thousand barrels per day by 1990.

The line length and size required to transport 250 thousand barrels per day from Piceance Basin to Casper, Wyoming is estimated at about 250 miles of 20 to 24-inch pipe. The estimated cost of this system with associated, tankage, pump/reheat stations, etc. is estimated as follows:

Spur Line Economics

Terminals:	Piceance Creek To Casper, Wyoming
Mileage:	250 Miles
Flow Rate	250 MBPD Maximum
Tankage:	2,000 thousand barrels at Piceance Basin
Diameter:	24 inches

Capital Cost	1980 MM$
Line, Stations, Etc.	73.0
Tankage	8.0
Total	81.0

Operating Cost	1980 Dollars Per Barrel 250 MBPD	100 MBPD	50 MBPD
Revenue	0.79	1.53	2.75
Variable Cost	0.30	0.30	0.30
Fixed Cost (Excluding Depreciation)	0.22	0.56	1.10
Depreciation	0.09	0.22	0.45
BFT Income At 20% Investment	0.18	0.45	0.90

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PROCESSING ECONOMICS AND SHALE OIL VALUE

GENERAL

Investment requirements and operating costs associated with refining whole shale oil vary depending upon the shale oil's properties, processing capabilities of the existing refinery, and definition of the base charge and product slates.

Shale oil can be processed in conventional petroleum refining facilities if the high nitrogen content is reduced. As discussed in Section D, nitrogen content is of primary concern in the naphtha and gas oil streams due to its deactivation of catalyst in catalytic reformers and fluid catalytic crackers. Once the nitrogen content problem is resolved, investment requirements and operating costs for downstream units such as hydrocrackers, catalytic reformers, and fluid catalytic crackers are equivalent to those for conventional crude oil streams.

Two basic options exist for handling shale oil in a refinery:

- Raw shale oil hydrotreating and subsequent blending into the crude oil charge is the simplest and most direct approach. Large volumes of oil can be handled in this way since no further downstream changes are needed and because optimal sized raw shale oil treaters are 20 thousand barrels per stream day or larger.

- Distillation of the whole shale oil followed by separate hydrotreating of the naphtha, distillate, and gas oil sidestreams is the more complex and investment-intensive approach. This configuration allows hydroprocessing the components of shale oil to the extent required to protect downstream catalyst when the shale oil fraction is blended into the crude oil fraction. Small volumes of shale oil might be slipstreamed into existing refineries with excess hydrogen and hydrotreating capacity. Extremely large volumes of shale (100 million barrels per day +) can be accomodated by separate distillation units and asociated downstream hydrotreating.

Raw shale oil hydrotreating can be integrated with an existing refinery as shown in Figure E-1. Figure E-2 depicts the probable configuration employing raw shale oil distillation and downstream hydrotreating.

FIGURE E-1

CONFIGURATION TO PROCESS SMALL PERCENTAGE OF
SHALE OIL IN AN EXISTING REFINERY

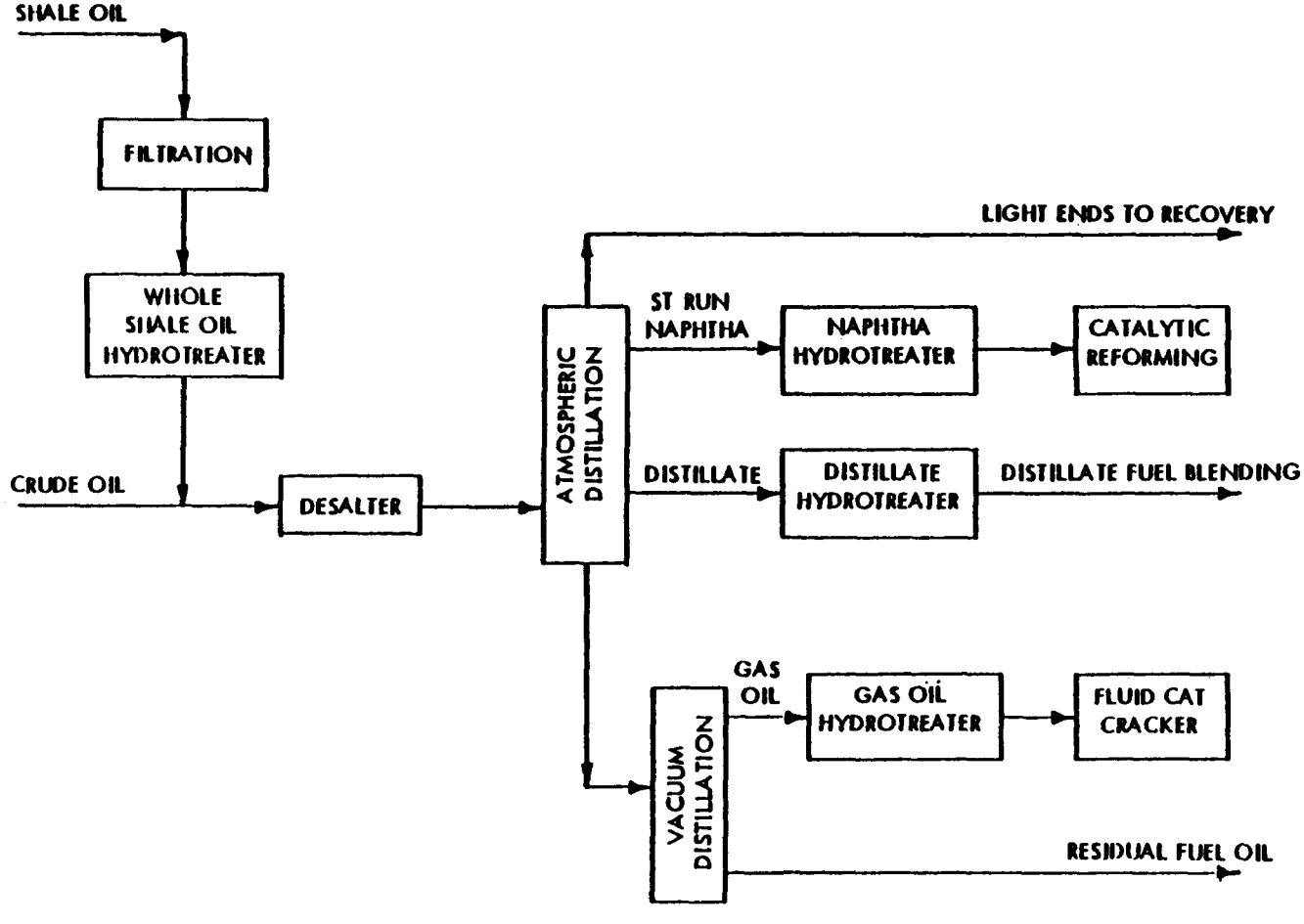


FIGURE E-2

CONFIGURATION TO CHARGE LARGE PERCENTAGE OF
SHALE OIL TO AN EXISTING REFINERY

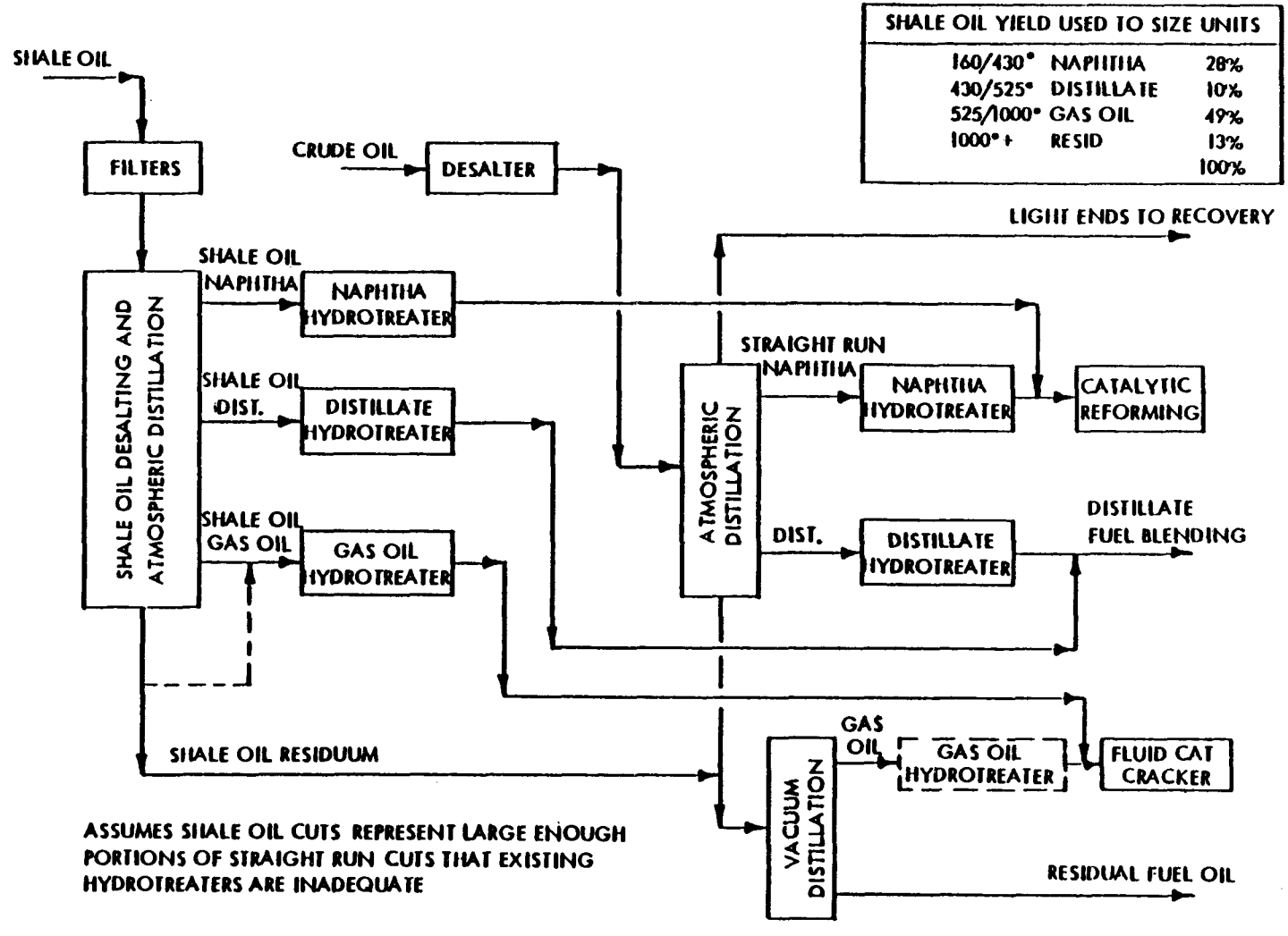


TABLE E-1

BASES FOR SHALE OIL PROCESSING
GENERAL ECONOMIC ANALYSIS

I. INVESTMENTS

A. Estimates for 1980 costs: Nelson's Construction Index=850.

B. Tankage investment estimated at $9.20 per barrel.

C. Other offsite investment taken as 30 percent of onsite investment.

II. OPERATING COST FACTORS

A. Salaries and wages estimated at 2.4 times direct labor. Direct labor rate is $9.20 per operator hour.

B. Fuel cost @ $2.25 per million BTUs.

C. Power cost @ $25.00 per thousand kilowatt hours.

D. Cooling water cost @ $0.011 per thousand gallons.

E. Maintenance taken as 2 percent of offsite + 4 percent of onsite investment per year.

F. Plant supplies estimated at 8 percent of maintenance.

G. Taxes and insurance estimated at 2 percent of total investment per year.

H. Depreciation based on 10 percent of total investment per year.

I. Before tax profit is 20 percent of total investment per year.

J. Stream day factor = 0.9.

Economic considerations for each approach are discussed in the following sections. Table E-1 lists the bases for our economic calculations.

Hydrogen Economics

Hydrogen consumption is the most significant factor in determining the cost of operating hydrotreaters. Excess hydrogen in refineries is burned as plant fuel; therefore, the lowest hydrogen value is based on this heat content. With fuel valued at $2.30 per million BTU, hydrogen is valued at $0.86 per thousand cubic feet. Typical refinery hydrogen streams are at relatively impure concentrations, and prior to compressing to the required level for the hydrotreating unit, a cryogenic enrichment step should be taken. The cost of such a process is estimated at $0.08 per thousand standard cubic feet, bringing the minimum hydrogen value to $0.94 per thousand standard cubic feet.

In a situation where no hydrogen is available, it must be purchased or produced on-site. Operating costs for a hydrogen plant, shown in Table E-2, indicate the value of manufactured hydrogen to be $2.37 per thousand standard cubic feet. This represents the maximum hydrogen cost to a refiner. A situation in which some excess hydrogen is available with the balance by manufactured hydrogen would result in an average price in the range of $0.94 to $2.37 per thousand standard cubic feet.

TYPICAL RAW SHALE OIL HYDROTREATING

As shown in Figure E-1, filtered raw shale oil can be hydrotreated and then blended in the charge prior to desalting. For a unit capable of hydroprocessing 10 thousand barrels per stream day, capital is estimated at:

- **Onsite Investment**—$31.2 million (including the filtration equipment).
- **Offsite Investment**—$9.4 million (includes $1.3 million for tankage to handle 15 days of shale oil inventory).

Other offsite requirements include utilities, distribution and production equipment, environmental facilities, roads, buildings, etc. The raw shale oil hydrotreater would operate at conditions very similar to an atmospheric crude oil residuum desulfurizer, and would require a correspondingly similar investment.

TABLE E-2

TYPICAL HYDROGEN PLANT OPERATING COSTS
(1980 Dollars Per Thousand Standard Cubic Feet)

Naphtha Feed ($0.43/Gallon)	0.87
Salaries and Wages	0.01
Fuel	0.72
Power	0.10
Cooling Water	0.01
Maintenance	0.06
Plant Supplies	-
Catalysts and Chemicals	0.03
Taxes and Insurance	0.03
Depreciation	0.17
Total Manufacturing Cost	2.00
Before Tax Profit (20 Percent Total Investment/Year)	0.37
Hydrogen Transfer Price	2.37

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Table E-3 details the actual consumptions and costs per barrel of feed for a 10 thousand barrel per stream day raw shale oil hydrotreater. The total cost of operating the unit is between $6.99 and $9.85 per barrel charged. This range is due to the variable hydrogen cost which contributes $1.88 to $4.74 per barrel. No additional processing costs would be attributed to processing shale oil since we have assumed that the whole shale oil hydrotreating approach will be chosen when the treated shale oil distillation products will be adequately handled by downstream equipment. Figure E-3 displays the sensitivity of economics to both unit size and hydrogen value.

TYPICAL RAW SHALE OIL DISTILLATION AND SIDE STREAM HYDROTREATING

For this case a facility capable of handling 50 thousand barrels per stream day of shale oil was analyzed. Estimated investment requirements are detailed in the following table:

	$MM 1980
Onsite	
50 MBPSD Atmospheric Distillation Unit	11.6
14 MBPSD Shale Naphtha Hydrotreater	8.2
5 MBPSD Shale Distillate Hydrotreater	6.5
25 MBPSD Shale Gas Oil Hydrotreater	63.6
Total Onsite	89.9
Offsite	
25 Days of Tankage	11.5
Other Offsites (30 Percent of Onsite)	26.9
Total Offsite	38.4
Total Investment	128.3

The investment for the shale oil distillation unit is equal to that for a crude oil distillation unit of the same capacity. Operating costs of all units in this downstream system are presented in Table E-4.

TABLE E-3

TYPICAL RAW SHALE OIL HYDROTREATING COSTS AND CONSUMPTION FACTORS (1980)

Investment Basis:

	1980 $MM
10 MBPSD Shale Oil Hydrotreater	31.2
Offsite Investment	9.4
Total Investment	40.6

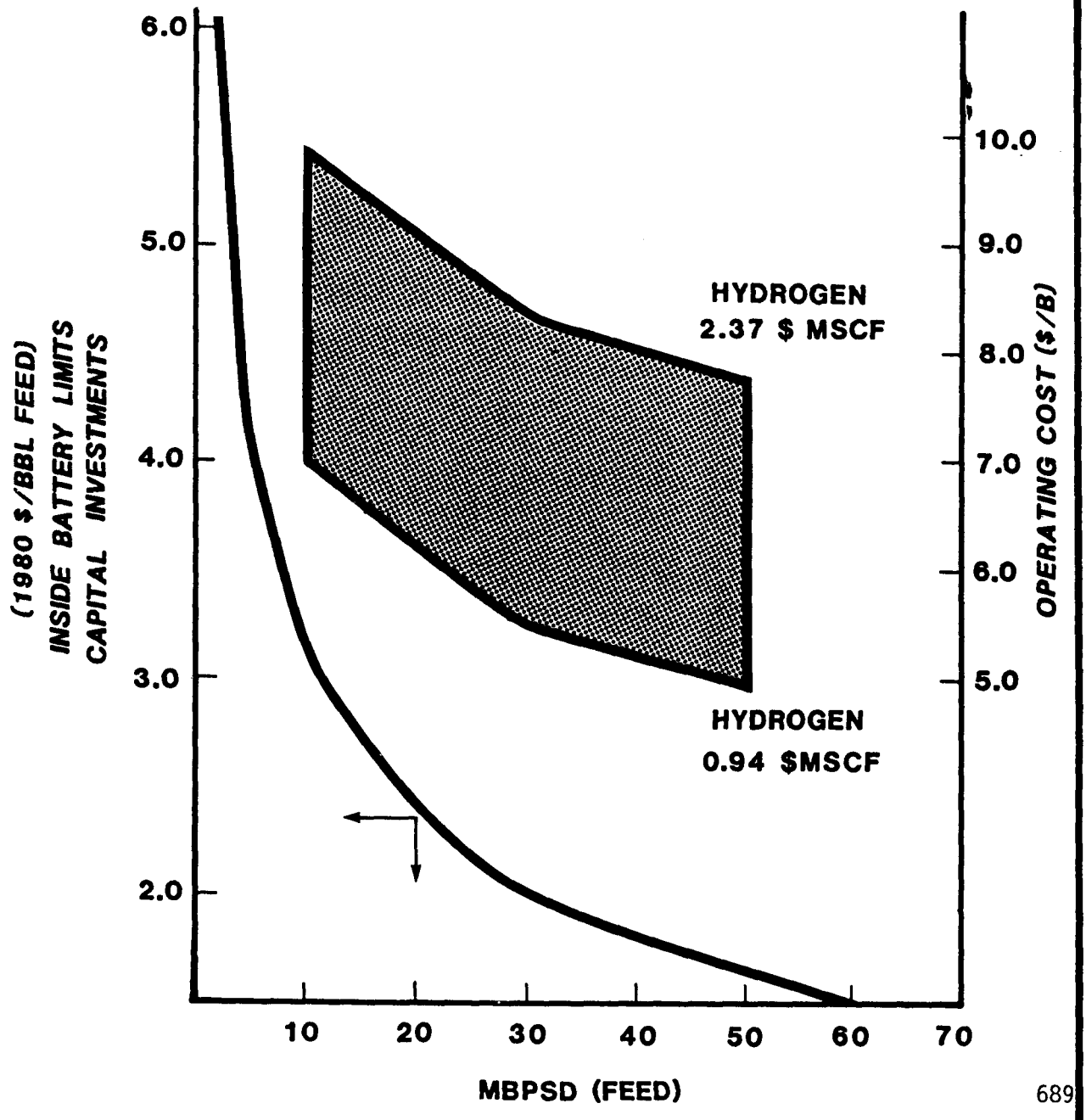
Operating Cost	1980 $/Barrel
Fuel (73.7 MBTU/Bbl)	0.17
Power (6.2 KWH/Bbl)	0.16
Cooling Water (0.10 MGal/Bbl)	0.01
Salaries and Wages (3 Men/Shift)	0.16
Maintenance	0.44
Plant Supplies	0.03
Catalyst and Chemicals	0.20
Taxes and Insurance	0.25
Depreciation	1.24
Total Processing Cost Excluding Hydrogen	2.66
Hydrogen (2,000 SCF/Bbl)	1.88-4.74
Total Processing Cost	4.54-7.40
Before Tax Profit	2.45
Total Operating Cost	6.99-9.85

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FIGURE E-3

TYPICAL RAW SHALE OIL HYDROTREATER ECONOMICS

BASIS: (1)2000SCF H2/BBL FEED
(2) 1980 DOLLARS



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TABLE E-4

TYPICAL SHALE OIL DISTILLATION AND SIDE STREAM HYDROTREATING
1980 OPERATING COSTS

Investment Basis:	1980 $MM
50 MBPSD Distillation Unit	11.6
14 MBPSD Naphtha Hydrotreater	8.2
5 MBPSD Distillate Hydrotreater	6.5
25 MBPSD Gas Oil Hydrotreater	63.6
Total Onsite	89.9
Offsite Investment	38.4
Total Investment	128.3

	50 MBPSD Distillation	14 MBPSD Naphtha Hydrotreater	5 MBPSD Distillate Hydrotreater	25 MBPSD Gas Oil Hydrotreater	
Operating Costs (1980 $/Bbl Unit Feed)					
Fuel	0.20	0.03	0.09	0.17	
Power	0.01	0.05	0.04	0.16	
Cooling Water	0.01	0.01	0.01	0.01	
Salaries & Wages	0.16	0.10	0.10	0.10	
Maintenance	0.04	0.08	0.18	0.37	
Plant Supplies	0.01	0.01	0.01	0.03	
Catalyst and Chemicals	0	0.03	0.03	0.15	
Taxes and Insurance	0.02	0.05	0.10	0.21	
Depreciation	0.13	0.27	0.56	1.04	
Total Processing Cost Excluding Hydrogen	0.58	0.63	1.12	2.24	
Hydrogen	-	0.61-1.54	0.94-2.37	1.88-4.74	
Total Processing Cost	0.58	1.24-2.17	2.06-3.49	4.12-6.78	
Before Tax Profit	0.26	0.54	1.12	2.07	
Total Operating Cost	0.84	1.74-2.71	3.18-4.61	6.19-9.05	
					Composite
$/Bbl Raw Shale Oil Feed	0.84	0.49-0.76	0.32-0.46	3.60-4.52	5.25-6.56

The shale oil side stream hydrotreaters require more investment than similar units for crude oil-derived streams. This is due to the high operating temperature and pressure, and (in some cases) lower space velocities for the shale oil units. The onsite investment required for crude oil fraction hydrotreaters is compared to that for shale oil fraction hydrotreaters in the following table. All units are sized to process 10 thousand barrels per stream day.

	(Million 1980 Dollars)		
	Naphtha	Distillate	Gas Oil
Crude Stream Unit	4.8	7.0	10.6
Shale Oil Stream Unit	6.5	10.6	31.2
Increased Investment For Shale Oil Stream (Percent)	35.4	51.4	194.3

The investment increase for shale oil hydrotreating is substantially higher for the heavier fractions due to the significantly higher severity required to reduce the nitrogen content of the heavier material.

The costs for operating each unit in the shale oil distillation/hydrotreating facility are shown in Table E-4. The total costs per barrel charged each unit are summarized as follows:

Total Operating Costs For Shale Oil Distillation And Hydrotreating Units
(Dollars Per Barrel)

	$/Bbl Feed	$/BBL Raw Shale Oil
Distillation Unit	0.84	0.84
Naphtha Hydrotreater	1.74 - 2.71	0.49 - 0.76
Distillate Hydrotreater	3.18 - 4.61	0.32 - 0.46
Gas Oil Hydrotreater	6.19 - 9.05	3.60 - 4.52
Composite		5.25 - 6.56

TABLE E-5

SHALE OIL DISTILLATION AND SIDE STREAM HYDROTREATING CONSUMPTION FACTORS

	Distillation	Naphtha Hydrotreater	Distillate Hydrotreater	Gas Oil Hydrotreater
Fuel (MBTU/Bbl)	87.9	12.3	37.9	73.7
Power (KWH/Bbl)	0.24	2.0	1.43	6.2
Cooling Water (MGal/Bbl)	0.50	0.87	0.07	0.11
Operators Per Shift	3	2	2	2
Hydrogen (SCF/Bbl)	-	650	1,000	2,000

Table E-5 shows the consumption rates for each unit.

The cost of operating the distillation unit should not vary significantly from shale oil to crude oil feeds. Hydrotreater operating costs are higher for shale oil units. Table E-6 compares the cost to operate crude oil hydrotreating units with shale oil units of equal size.

The average total cost per barrel charged is $0.90 less for crude oil naphtha than for shale oil naphtha; $1.62 less for crude oil distillate; and $5.39 less for crude oil-derived gas oils. As with investments, the severity requirements for shale oil increase dramatically for the higher boiling range materials.

SITE-SPECIFIC ECONOMICS

Pace has examined the economics of an on-site 50 thousand barrels per stream day raw shale oil (RSO) hydrotreater in 1987. We have looked at the economics of this proposed system and have found several key issues. First, the hydrogen and fuel requirements may exceed that which is obtainable from the surface retort off gas make. Figure E-4 illustrates and provides our estimated volumes required to make a self-sufficient system on-site at the Occidental tract.

There will be increased demands for fuel when the hydrotreating option is brought onstream. The shale oil hydrotreater (SOHT) will require process fuel, and the hydrogen plant will require both fuel and feed material to be turned into hydrogen. As illustrated, the contained hydrogen plus that which can be turned into hydrogen from the surface retort (SR) off gas will be adequate to meet the hydrogen demand. However, the system will be slightly short of process fuel, in which case a small amount of shale oil naphtha can be used as process fuel.

Prior to the introduction of this SOHT system, the project will be producing and selling power with the SR off gas. Occidental provided a figure of 3.5 cents per kilowatt hour (1980) to Pace as the expected sales value of the produced power. At this value we determined the implied value of the off gas to the plant to be $2.17 per million BTUs (1980). Table E-7 presents the site-specific hydrogen plant economics using $2.17 per million BTU of fuel and 3.5 cents per killowatt hour power. At the size plant this project requires (72.5 standard cubic feet per day) the implied cost will be about $1.45 per standard cubic feet hydrogen (1980). Transferring this into the actual SOHT economics (Table E-8) the implied cost of total upgrading would be $5.97 per barrel (1980) of raw shale oil feed. Several factors help keep this cost down below the typical case presented earlier: (1) the size of the SOHT at 50 thousand barrels per stream day (Figure E-3); (2) the decreased hydrogen requirement due to the raw shale oil properties that Occidental will be producing. The hydrogen consumption was calculated on reaching a 1300-1400 ppm basic N_2 content in the 650/1050°F shale oil cut in order to make suitable catalytic cracking feedstock.

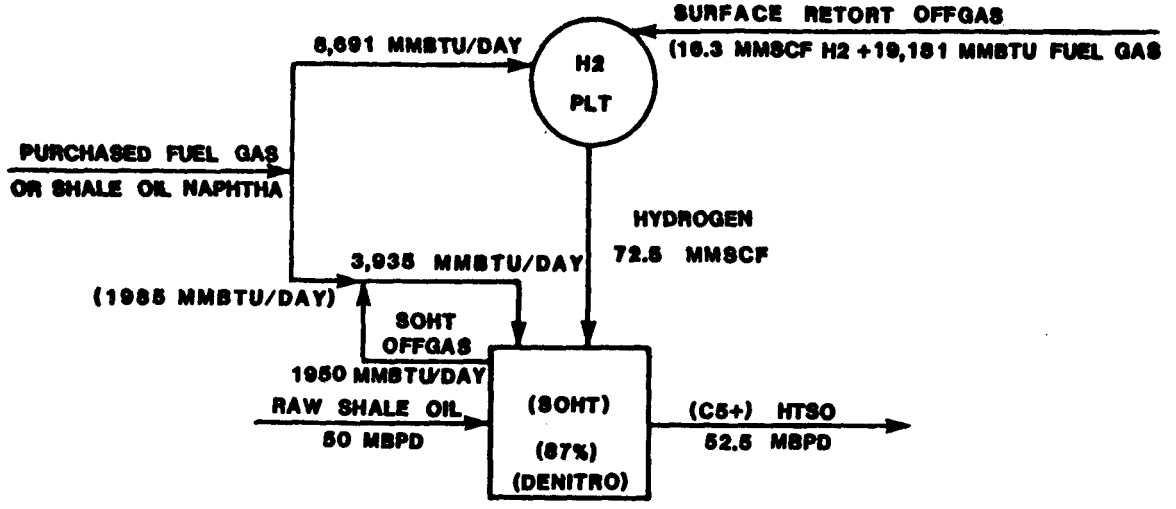
TABLE E-6

COMPARISON OF CRUDE OIL AND SHALE OIL SIDE STREAM HYDROTREATING (All Units 10 MBPSD)

	Whole Shale Oil	Naphtha		Distillate		Gas Oil	
		Crude	Shale Oil	Crude	Shale Oil	Crude	Shale Oil
Investment ($MM)							
Onsite	31.2	4.8	7.2	7.0	10.6	10.6	31.2
Offsite	9.4	1.4	2.1	2.1	3.2	3.2	9.4
Total	40.6	6.2	9.3	9.1	13.8	13.8	40.6
Operating Costs ($/Bbl)							
Processing Cost Exc. Hydrogen	2.66	0.68	0.64	0.77	0.96	0.97	2.76
Hydrogen	1.88-4.74	0.09-0.47	0.61-1.54	0.28-0.71	0.94-2.37	0.56-1.42	1.88-4.74
Profit	2.45	0.35	0.53	0.52	0.79	0.79	2.07
Total Cost	6.99-9.85	1.12-1.50	1.73-2.71	1.57-2.00	2.69-4.14	2.32-3.18	6.71-9.57
Average Cost	8.42	1.31	2.22	1.79	3.41	2.75	8.14
Increase in Average Cost For Shale Oil Over Crude Oil Streams		-	0.90	-	1.82	-	5.39

FIGURE E-4

PLANT SITE SHALE OIL HYDROTREAT SYSTEM



SYSTEM REQUIREMENTS

		FUEL MBTU/DAY	HYDROGEN (MSCF/DAY)
DEMAND			
	H2FEED	14,612	
	H2FUEL	13,260	
	SOHT FUEL	3,935	72.5
	TOTAL	31,807	72.5
SUPPLY			
	SOHT OFFGAS	1950	
	SR OFF GAS	19,181	72.5
	PURCHASED FUEL GAS	10,676 (2,135)	
	(OR SHALE OIL NAPHTHA) (MBPD)	31,807	72.5

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TABLE E-7

PROPOSED HYDROGEN PLANT OPERATING ECONOMICS

Basis: 72.5 Million Standard Cubic Feet Per Day Hydrogen

		MM $ (1980)
INVESTMENT		
Onsite		20.3
Offsite (@ 30% onsite)		6.1
Total Investment		26.4
MANUFACTURING COST		
Fuel Gas Feed	(0.26 MMBTU @ $2.17 MMBTU)	0.56
Salaries and Wages		0.01
Fuel	(0.183 MMBTU @ $2.17/MMBTU)	0.40
Power	(2.16 KWH @ 3.5¢/KWH)	0.08
Cooling Water		0.01
Maintenance	@ 3% Investment	0.03
Plant Supplies		-
Catalysts and Chemicals		0.03
Taxes and Insurance	@ 2% Investment	0.03
Depreciation	@ 10% Investment	0.10
Total Manufacturing Cost		1.25
Before Tax Profit	(20% Total Investment/Year)	0.20
Hydrogen Transfer Price		1.45

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SHALE OIL VALUE

Looking at raw shale oil's value to the refining industry, we have run several Linear Program (LP) refinery models to determine the relative value of raw shale oil.

The typical refinery selected for analysis was tailored to reflected an average PADD 2 refinery. The major processing units incorporated in the refinery included atmospheric and vacuum crude oil distillation, naphtha hydrotreating and reforming, fluid catalytic cracking (FCC), and alkylation. The base feedstock slate to the refinery was assumed to consist of a 75/25 mix of low/high sulfur crude oils.

Raw shale oil processing in this refinery was analyzed within a framework of alternative cases to examine the requirements for:

1. Expanding the base refinery's processing capacity, with North Slope crude oil as the incremental feedstock.

2. Expanding the base refinery's processing capacity, with Occidental's shale oil as the incremental feedstock.

3. Substituting high sulfur asphaltic crude oil in place of low sulfur crude oil.

4. Substituting Occidental's shale oil in place of low sulfur crude oil.

In each case, the expansion or substitution volume was fixed at 30 percent of the base refinery's processing capacity. Simulations of the refinery operations were developed using Pace's Refinery/Petrochemical Linear Programming (LP) Model. The product slates in each pair of alternate cases were maintained substantially identical so that the differences between the refining values of shale oil and each crude oil could be determined on the basis of the different processing requirements.

In each shale oil case, a primary hydrotreater was included in the refinery process configuration for treating the raw shale oil feedstock. Operating severity (expressed in terms of percent denitrogenation) was limited to a range of 87.0 to 97.5 percent. The shale oil fractions were then directed to downstream processing units, including secondary hydrotreating, as required to meet the requirements for product volumes and quality specifications.

Results of thes studies are as follows:

- The optimum shale oil hydrotreating severity for the processing configuration analyzed is in the range of 87 to 89 percent. Further studies are required to establish the economic and process yield interactions between shale oil hydrotreating severity and conventional refinery processes.

TABLE E-8

PROPOSED WHOLE SHALE OIL HYDROTREATING ECONOMICS

Basis: 50 Thousand Barrels Per Stream Day Shale Oil Hydrotreater

		MM $ (1980)
INVESTMENT		
Onsite		82.2
Offsite (@ 30% onsite)		24.7
Total Investment		106.9
OPERATING COST		$/Bbl
Fuel	(73.7 MBTU @ $2.17 MMBTU)	0.16
Power	(6.2 KWH/Bbl @ 3.5¢/KWH)	0.22
Cooling Water	(0.10 MGal/Bbl)	0.01
Salaries and Wages	(3 Men/Shift)	0.15
Maintenance	@ 3% Investment	0.28
Plant Supplies		0.01
Catalysts and Chemicals		0.19
Taxes and Insurance	@ 2% Investment	0.12
Depreciation	@ 10% Investment	0.63
Total Processing Cost Excluding Hydrogen		1.65
Hydrogen	(1,450 SCF/Bbl)	2.10
Total Processing Cost		3.75
Before Tax Profit	(20% Total Investment/Year)	2.22
Total Operating Cost		5.97

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- The refining value of Occidental's raw shale oil in the refinery selected for this analysis is estimated to be $3.37 per barrel less than the value of average foreign import crude oil. This is based on the differences in variable operating costs, modest changes in product slate, and capital charges approximating a 10 percent DCF rate of return on the incremental investment requirements (1980).

  On the same basis, the refining value of Occidental's shale oil is estimated to be $1.31 per barrel less than the selected high sulfur asphaltic domestic crude oil.

- Refining cost diffentials between shale oil and conventional crude are most sensitive to incremental capital, particularly for the shale oil hydrotreater. For that unit, estimates ranging between $1,500 and $3,000 per barrel of (on-site only) capacity were found in the literature. In view of the relatively lower contaminant levels and residual content of Occidental's shale oil compared to other shale oils, the cost could be expected to trend toward the lower end of the range. As is shown in Table E-8 and Figure E-3 the (1980) onsite investment cost for a 50 thousand barrels per steam day SOHT is $1,644 per barrel.

  Also, in all cases examined, a large component of the incremental capital cost covered expansion of the FCC unit. This capital cost was arrived at based upon throughput volume only. This approach could possibly penalize the shale oil case since the incremental feedstock will have been severely hydrotreated which may allow for a lower cost cracking expansion.

- Most shale oil contains less light, low boiling point material and less heavy residual material than an average petroleum crude oil. The boiling range for shale oil is typically 375°F to 1,030°F. As refinery product demands shift to more fuels products (kerosene, No. 2 fuel oil, No. 6 fuel oil, etc.), and less motor gasolines, the refining value of shale oil will increasing relative to other crude oils.

- Due to this composition difference raw shale oil has an inherent value over average import crude oil of about $3.50 to $6.50 per barrel. However, the net effect, after considering added treating costs, is the $3.00 to $3.50 delta debit between raw shale oil and average foreign.

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TABLE E-9

PADD 2 CRUDE OIL QUALITIES AND VALUES TO REFINING
(Constant 1980 Dollars)

	Average RTS *		Foreign		ANS *		Raw Shale Oil	
	API	$/Bbl	API	$/Bbl	API	$/Bbl	API	$/Bbl
1980	35.0	28.38	35.2	34.12	27.0	24.32	19-24	31.12
1985	34.2	32.42	33.8	32.38	27.0	31.03	19-24	29.01
1990	33.0	38.07	31.8	38.03	27.0	37.03	19-24	35.28
1995	32.8	44.70	30.3	44.28	27.0	43.71	19-24	42.21
2000	32.5	52.50	30.8	52.21	27.0	51.57	19-24	50.32

*RTS = Runs to Stills
ANS = Alaskan North Slope

Taking all factors into account, the value of Occidental's raw shale oil will be tied into our forecast of conventional crude oils as presented in Table E-9. Several things are happening to these crude oil prices during the 1980 to 2000 period. First, all domestic crude (including Alaskan North Slope) are reaching world oil price between 1980 and 1985. Secondly, foreign crude oil is decreasing slightly in constant dollars between 1980 and 1985. This is due to an adequate to over-supply position of world crude oil. Past 1985 the real constant dollar price of all crude oils are expected to increase at about a 3.0 percent per year real growth rate. Raw shale oil will be tracking incremental oil supply to the PADD 2 and PADD 3 refiners which we see as either foreign oil or possibly ANS.

With the forecast developed, the netback value of Occidental's raw shale oil at plant site was calculated.

Netback Value of Raw Shale Oil
(1980 Dollars Per Barrel)

	1985	1990	1995	2000
PADD 2A				
Refining Value	29.01	35.28	42.21	50.32
Less: Plant Cost	0.80	0.91	1.00	1.10
Less: Spur Line Cost	1.53 - 2.75	1.53	1.16	0.79
Netback ($/Bbl)	26.65 - 25.43	37.84	40.05	48.43

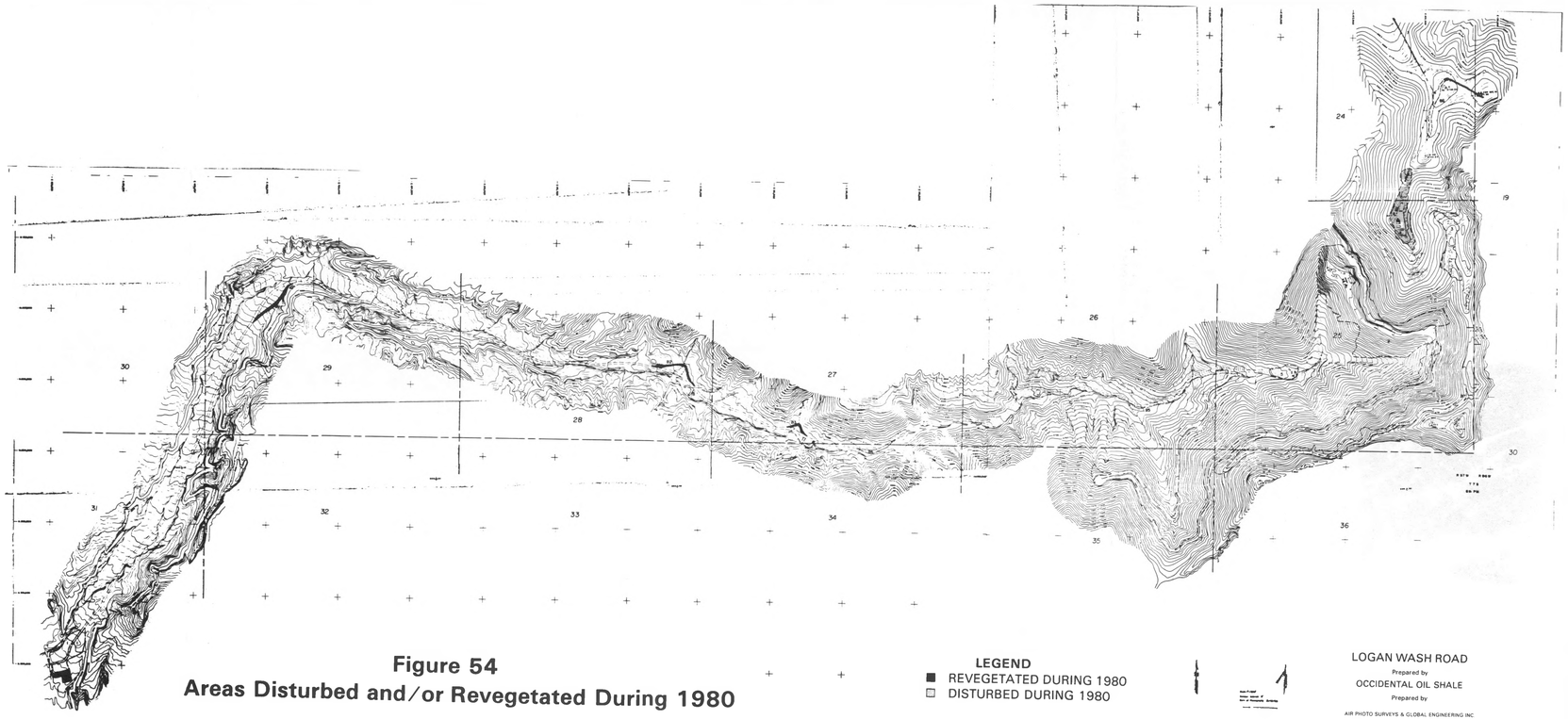


Figure 54
Areas Disturbed and/or Revegetated During 1980

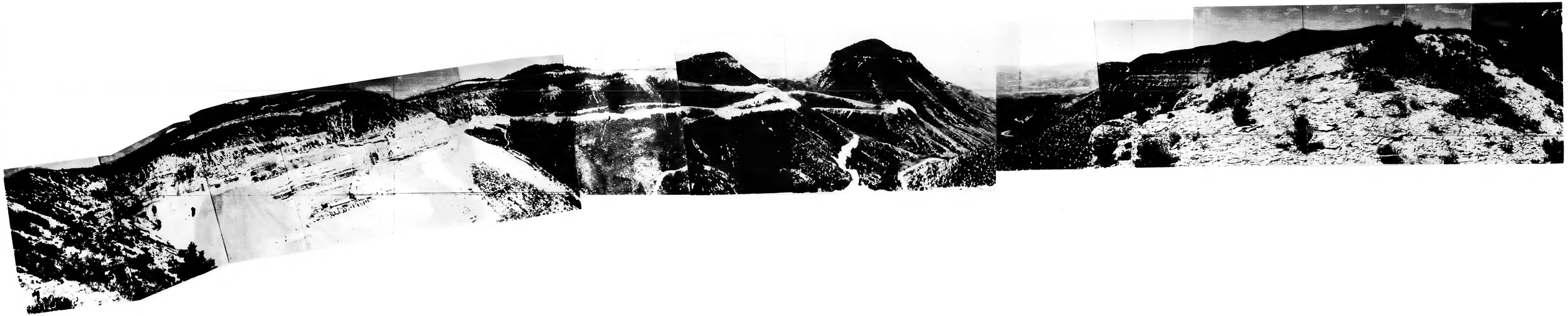


Figure 55
360° Mosaic of Photo Point 20