SAN/1137-10

MASTER

GEOTHERMAL LOOP EXPERIMENTAL FACILITY

SDG&E

DOE CONTRACT NO. EY-76-C-03-1137

APRIL 1978

QUARTERLY REPORT

SAN/1137-10

SDG&E - DOE

GEOTHERMAL LOOP EXPERIMENTAL FACILITY

QUARTERLY REPORT

FOR THE PERIOD

JANUARY - MARCH, 1978

W. S. Bischoff
H. K. Bishop
C. S. Cooney
W. H. Hanenburg
G. J. Hoaglin
W. O. Jacobson
D. K. Mulliner
D. G. Newell
C. R. Swanson

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564 6000

San Diego Gas & Electric Company
P.O. Box 1831
San Diego, California 92112

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REA

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ABSTRACT

The Geothermal Loop Experimental Facility (GLEF) utilizes a four stage flash/binary process for the extraction of energy from a high temperature, high salinity, liquid-dominated resource. Since plant start-up in May, 1976, a substantial amount of information has been obtained on the operation of the plant, components, brine and steam composition, production and injection wells, and the potential of the Niland Reservoir.

This Quarterly Report discusses the general operation and activities of the GLEF during the period January, 1978 through March, 1978, in the GLEF Operations Section. The production and injection well encountered no unusual difficulties as described in the Reservoir Operation Section. Scrubber performance tests were rerun this period and are discussed in the Testing Section. The Systems Chemistry Section discusses steam ph, conductivity, and chemical composition. Also discussed are brine and scale properties. In the Maintenance Section, pigging and component optimization efforts are discussed. The injection pump difficulties and condenser plugging problems are detailed in the Special Problems Section. The Other Activities Section discusses the feasibility study for a 50 MWe plant and H_2S abatement.

CONCISE DESCRIPTION OF THE NILAND GLEF

Early in 1972, the concept of building a Geothermal Loop Experimental Facility (GLEF) at the Niland Known Geothermal Resource Area (KGRA) was originated. This area is located on the southern shore of the Salton Sea near Niland, California. SDG&E, in cooperation with Magma Power Company, drilled and flowed a geothermal test well to demonstrate the ability of the Niland Reservoir to produce a significant amount of hydrothermal fluid capable of generating electric power. See Figure 1-1 for the general appearance of the GLEF.

In May, 1975, construction of the GLEF began and start-up of plant operations commenced on May 3, 1976. This 10-megawatt sized facility is the first of its kind for testing high temperature (in excess of 500°F downhole) and high salinity (250,000 ppm) geothermal resources utilizing a flash/binary conversion cycle for the production of energy.

Magma Power Company, jointly with the New Albion Resource Company (NARCO), supply geothermal fluid (brine) from two production wells, Magmamax No. 1 and Woolsey No. 1. These are located near the test facility in the center of the anomaly. Magmamax No. 1 produces a two phase mixture of brine with a temperature and pressure at the wellhead of 440°F and 350 psig, respectively, with an average flowrate of approximately 400,000 lbs/hr. Woolsey No. 1 produces

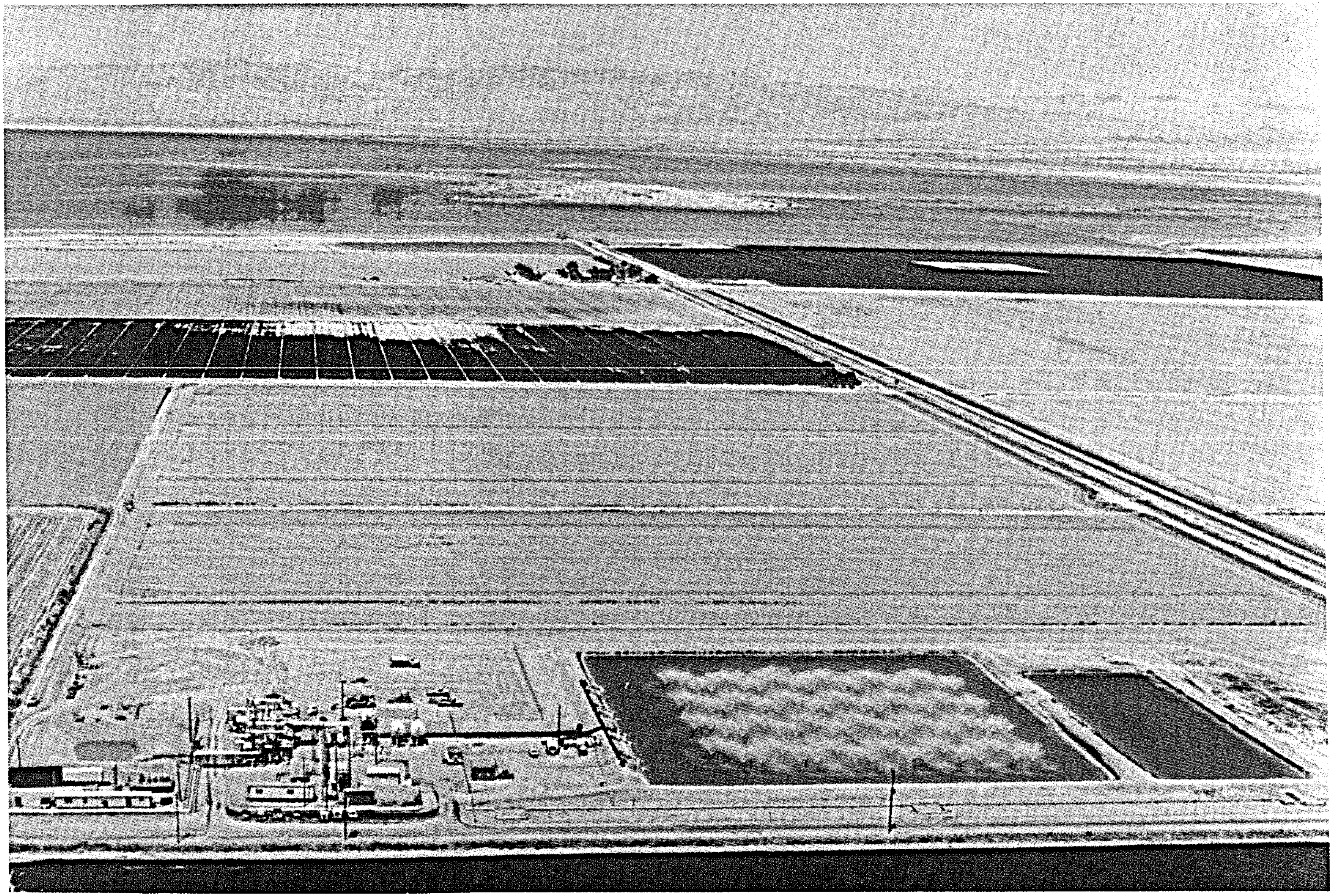


FIGURE 1-1

GEOTHERMAL LOOP EXPERIMENTAL FACILITY
Niland, California

a two phase mixture of brine with a temperature and pressure at the wellhead of 380°F and 200 psig, respectively, with a design flowrate of approximately 400,000 lbs/hr. Woolsey has been used less frequently due to production difficulties. The plant is designed for an inlet temperature of 370°F, pressure of 165 psia, and a two-well flowrate of 800,000 lbs/hr. The produced brine flows through the plant and is then injected into the reservoir approximately one mile away through two injection wells, Magmamax No. 2 and No. 3. Magmamax No. 3 is the primary injection well with Magmamax No. 2 being used as a spare.

As brine enters the plant it is directed through four flash steam separators in series. The steam produced by the flashed brine passes through steam scrubbers (one for each stage) to remove salts and minerals. The scrubbed steam is condensed by six heat exchangers at approximately 200,000 lbs/hr, theoretically vaporizing the binary working fluid. This condensed steam, if not used for cooling water make-up, is recombined with the brine and injected into the reservoir. The noncondensible gases, primarily carbon dioxide with small amounts of other gases including hydrogen sulfide, are exhausted to the atmosphere through a 130 foot high stack.

The binary working fluid, which is currently distilled water, is partially vaporized when heated and flows through a throttling valve which simulates the pressure drop of a turbine. The binary working fluid is condensed back to a liquid and recirculated. This closed-loop binary system was originally designed for isobutane or a fluid with similar characteristics.

In addition to testing the flash/binary process, evaluation of the reservoir after the injection of cooled brine, and assessing the potential of the Niland geothermal reservoir, are underway.

San Diego Gas & Electric Company (SDG&E) owns the facility and manages its testing. SDG&E and the United States Department of Energy (DOE) jointly fund the activities of the facility.

1.0 GLEF OPERATIONS

The GLEF was operated for a total of 1284 hours during this reporting period: 315 hours in January, 238 hours in February and 731 hours in March. The plant has operated for a total of 7163 hours since start-up and 1166 hours since the last major cleaning.

The plant availability, excluding scheduled outages for maintenance and inspections during January was 100%, February 35% and March 100%, giving an average plant availability of 78% for the quarter. If all outages were included, the actual plant capacity factor for this quarter would be 58%. (See Table 1-1 and Figure 1-2)

During the majority of the operating time, Magmamax No. 1 was utilized for one well flow. Magmamax No. 3 was in use as the injection well via settling tanks operated by Imperial Magma.

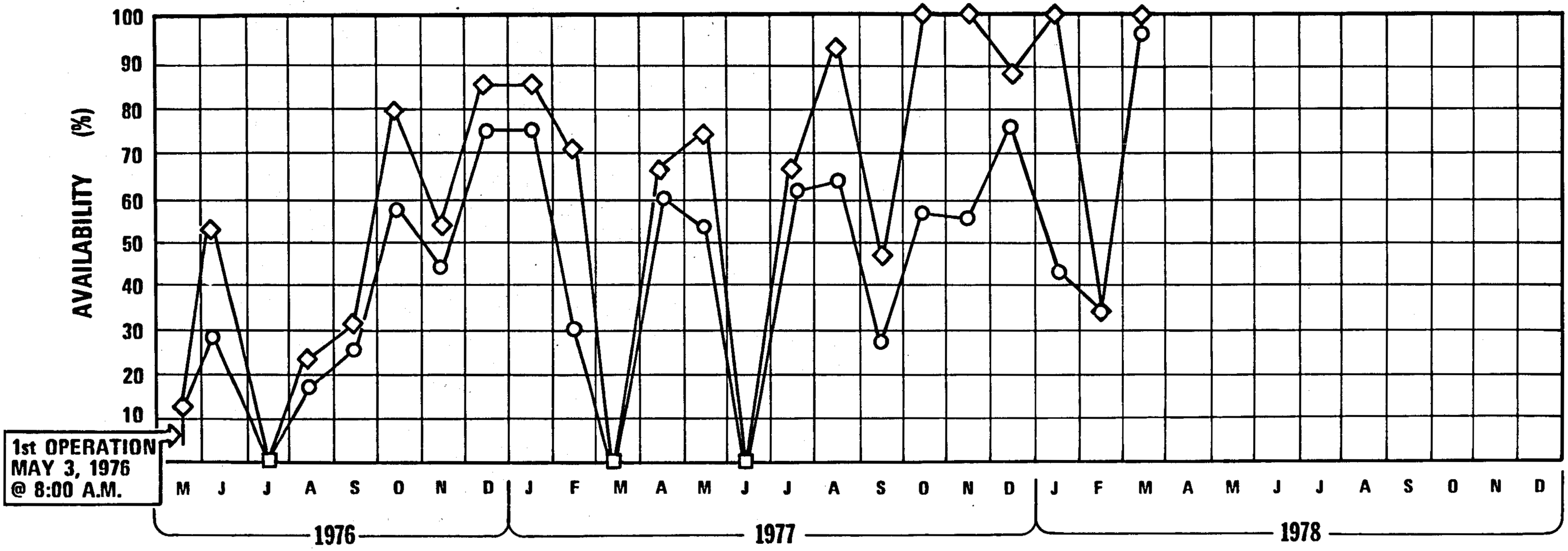
Two-well operation continued from January 1 to January 5 for a total flow rate of 400,000 lb/hr with heavy surging from the Woolsey well. This flow rate is approximately 50% of design capacity. During this operating period the injection pump (P-2) performance was below design. After inspection, this decreased performance was found to be due to partial plugging of the second stage bowl. Partial plugging was found to be due to an accumulation of rubber pieces from an earlier deterioration of a lining in a pinch valve. The pump was returned to the SDG&E machine shop for cleaning and overhaul.

GLEF AVAILABILITY 1978

MONTH	FOR MONTH					SINCE START-UP				
	TOTAL GLEF OPERATING HOURS	TOTAL HOURS IN THE MONTH	POSSIBLE HOURS (EXCLUDING SCHEDULED OUTAGES)	% AVAILABILITY BASED ON TOTAL HOURS	% AVAILABILITY (EXCLUDING SCHEDULED OUTAGES)	CUMULATIVE TOTAL GLEF OPERATING HOURS	CUMULATIVE TOTAL MONTH HOURS	CUMULATIVE POSSIBLE HOURS (EXCLUDING SCHEDULED OUTAGES)	% AVAILABILITY BASED ON TOTAL MONTH HOURS	% AVAILABILITY (EXCLUDING SCHEDULED OUTAGES)
JANUARY	315	744	315	42.3	100	6,146	15,296	11,084	40.2	55.4
FEBRUARY	238	672	672	35.4	35.4	6,384	15,968	11,756	40.0	54.3
MARCH	731	744	731	98.3	100	7,115	16,712	12,487	42.6	57.0
APRIL										
MAY										
JUNE										
JULY										
AUGUST										
SEPTEMBER										
OCTOBER										
NOVEMBER										
DECEMBER										

TABLE 1-1

NILAND GEOTHERMAL LOOP EXPERIMENTAL FACILITY
1976, 1977 & 1978 AVAILABILITY BY MONTHS



○ Availability = No. of Hours of Plant Operation/Total No. of Hours in the Month.

◇ Availability = No. of Hours of Plant Operation/(Total No. of Hours in the Month - Hours of Scheduled Outages).

☐ Plant Shutdown for Major Overhaul

FIGURE 1-2

During this period chlorine was injected into the spray pond at a rate of 400 lbs/day to control algae growth and HCl was injected into the purge water of the injection pump bearings to maintain a pH of 5 and to reduce buildup of scale.

On January 5, the plant was shut down for overhaul, cleaning, and inspection. Routine items performed during this shutdown are described in Appendix A. During this shutdown period, modifications had been completed involving the installation of a holding tank and pump to store plant sump waste water and brine. This pump was set up to start and stop automatically with the level in the holding tank. The pump discharges the resulting effluent into the injection line.

On January 22, at 0230 the plant was started up using Magmamax No. 1 as the supply well and injecting into Magmamax No. 3 via the settling tanks. At 0940 of the same day, Woolsey No. 1 was brought on-line as the second supply well for continuation of two-well operation.

On January 24, the newly installed settling tank pump tested out satisfactorily.

At 2200 the plant was shut down to investigate pigs being damaged (See Pigging 5.1.1). Data from Woolsey No. 1 was reviewed. A review concluded that the brine was unrepresentative and that Woolsey #1 would be repaired or replaced.

On January 27, the plant was started up using Magmamax No. 1 as the supply well and Magmamax No. 3 for injection. The flow was directed through strainers prior to injection. Magma's settling tank pump was out of service until January 28 at 1445. Starting at this time, injection was through the settling tanks to Magmamax No. 3.

During the operation, the condenser pressure-drop increased to between 20 and 22 psig from a level of 6 psig. The cooling water (CW) flow was reduced to maintain a differential pressure at approximately 20 psig.

The plant was shutdown on February 3, to remove CW condenser headers for inspection. The tube sheets were found to be very dirty with debris and scale. (See Condensers 6.2). After cleaning and two days of operation (February 4 - February 6), the plant was shutdown.

On February 19, following a start up on February 17, the plant was shut down for three days because of difficulties with the injection pump (See Special Problems - 6.1 Injection Pump).

During the remainder of February and the month of March, several chemicals were injected into the cooling water system to alleviate problems with the spray pond. These include:

1) The injection of caustic at the P-10 Suction to raise the pH of condensate to approximately 9 upon entering the spray pond to decrease the amount of ammonia.

2) The injection of Zimmite Corporation's ZM136, a flocculent, to collect and settle the zinc and iron in the spray pond.

3) The injection of larger amounts of chlorine into the cooling water to kill any biological growth that might be present in the condenser tubes.

2.0 RESERVOIR OPERATION

2.1 Production Wells

Production for the entire quarter was from Magmamax No. 1 except intermittent two well flow using Woolsey No. 1. No major problems were encountered with the Magmamax #1 well. Preparations are under way for the flow test of Magmamax No. 2 well. This well has been primarily used as a spare injection well, but it is felt the well may be hot enough to use as a production well.

2.2 Injection Wells

Magmamax No. 3, the injection well during this period, operated satisfactorily for the entire period. Prior to injection, the brine was routed through a settling tank system (See January 1978 Quarterly Report) to precipitate solids from the brine to reduce the possibility of plugging the well. As indicated in the March, 1977 Quarterly Report, indications of well plugging in the Magmamax #3 well had been occurring. In March, 1978 a pilot reactor clarifier was installed using a side stream of brine from Magmamax #1 (see Appendix B). Brine exiting from the clarifier was averaging 40 ppm suspended solids in comparison to 100 ppm in the brine exiting the settling tank system. In addition, the dissolved silica was reduced from 300 ppm from the settling tanks to 170 ppm from the clarifier outlet.

The clarifier will be moved to the Magmamax No. 2 site to test its affect on reinjection brine from that well.

3.0 TESTING

During this reporting period, none of the tests from the Bechtel Test Program were formally conducted because revisions were in process (see Section 7.1). However, at Bechtel's request, a short test of scrubber efficiency versus wash water flowrate (Test 4.4.4) was conducted to provide input to the Bechtel/Ben Holt feasibility study for a 50 MWe power plant at the Niland reservoir. The results of this test are discussed below.

3.1 Purpose:

The purpose of conducting this set of scrubber performance tests was to determine if their efficiency varied with the rate at which wash water was added to them, with the plant operating at normal, one well-flow baseline conditions.

3.2 Procedure:

The GLEF was operated under one-well flow conditions during the scrubber tests. The temperatures and pressures of the steam entering the scrubbers were held as constant as possible and recorded at two hour intervals during each day of the test. On Monday, March 20, at approximately 1600 hours, the wash water flowrate was adjusted to the maximum amounts to be tested in each stage. Condensed steam samples from the inlet and outlet of each stage were taken beginning at 0800 hours the following day. Additional samples were taken at the hours noted in the data sheet (See Tables 3-1 and 3-2). Each of the samples were analyzed for chloride content using a titration procedure specified in the "Standard Methods for the Examination of Water and Wastewater", 14th ed., American Public Health Association, 1976".

The measuring of chloride content was selected as the simplest method of estimating the total amount of contaminants contained in the steam. A check of past steam analyses preformed at the GLEF showed that chloride content was roughly proportional to total dissolved solids content. The titration procedure used for chloride can be performed within minutes as opposed to several days for a TDS measurement.

On Tuesday, March 21 and each subsequent day of the test at about 1600 hours, the wash water flowrate was reduced to the level specified for the next day's test. The scrubbers were thus allowed to stabilize at the new flowrate throughout the night prior to collecting the next day's samples.

3.3 Results:

The chloride concentrations recorded on the first day of the tests are of questionable validity because each sample was titrated only once and the titrant used was too

STEAM SCRUBBER PERFORMANCE TESTS
— CHLORIDE CONCENTRATION IN ppm —

DATE	TIME	1ST STAGE		2ND STAGE		3RD STAGE		4TH STAGE	
		IN	OUT	IN	OUT	IN	OUT	IN	OUT
3-21	0800	70.9	31.5	13.6	12.6	23.6	11.0	36.7	70.3
	0900	44.6	14.2	25.2	21.5	26.2	14.2	996.	410.
	1000	42.0	33.1	17.3	11.5	14.2	10.0	50.4	70.3
	1200	145.	41.5	18.9	16.3	22.0	13.1	46.2	82.9
			34.1						
			36.7						
3-22	0800	76.2	31.2	18.8	12.9	18.0	9.61	68.4	81.5
		73.8	30.0	18.5	11.8	17.8	7.93	69.9	81.6
		75.1					8.61		
	0900	70.9	25.8	14.8	5.56	17.7	6.35	44.4	99.5
		69.7	26.4	12.9	5.61	16.9	6.94	43.0	98.9
	1000	132.	24.8	12.5	11.3	10.2	9.32	–	–
		132.	22.1	12.3	10.0	10.0	8.21	–	–
	1200	26.4	27.1	12.4	12.4	8.47	6.99	–	–
		24.5	26.2	13.9	11.7	7.41	7.20	–	–
	1400	75.4	26.2	14.9	12.1	11.3	9.42	–	–
		77.1	27.7	15.5	11.0	11.2	8.36	–	–
3-23	0800	121.	22.7	11.5	10.6	15.0	9.11	–	–
		121.	22.9	13.1	10.1	14.2	7.52	–	–
	0900	46.1	28.8	13.9	11.1	35.2	9.69	–	–
		46.4	27.3	15.0	11.6	34.0	7.62	–	–
	1000	39.8	21.3	14.7	11.8	9.48	11.1	–	–
		38.0	21.6	15.4	11.0	9.05	9.21	–	–
							8.84	–	–
	1200	69.1	25.8	14.8	12.1	10.8	11.0	–	–
		70.4	23.8	13.2	11.0	7.73	11.3	–	–
						8.58		–	–
	1400	66.6	20.9	13.5	10.3	22.3	8.84	–	–
		65.3	21.1	13.0	9.64	22.6	8.26	–	–
	1500	22.9	27.7	16.8	12.3	9.42	10.3	–	–
		23.1	26.8	17.8	11.5	10.1	9.05	–	–
3-24	0800	56.9	31.5	16.3	15.9	13.7	10.0	–	–
		56.9	29.5	16.5	14.1	12.0	9.16	–	–
	0900	30.2	30.8	11.5	10.4	11.4	9.00	–	–
		29.2	34.6	11.7	10.6	11.6	7.68	–	–
			31.0					–	–
	1000	65.0	25.4	11.9	10.4	11.1	10.1	–	–
		67.9	25.7	11.1	10.5	13.1	9.90	–	–
	1200	37.0	17.7	16.9	9.79	18.2	8.63	–	–
		37.0	18.3	15.5	9.95	20.1	8.42	–	–
	1400	128.	21.3	18.1	9.85	27.9	9.90	–	–
		134.	21.3	17.9	9.58	29.0	9.00	–	–

TABLE 3-1

STEAM SCRUBBER PERFORMANCE TESTS — WASH WATER FLOW RATES IN gpm

DATE	STAGE	SPECIFIED FLOW RATE	ACTUAL FLOW RATES AT INDICATED TIMES				
			0600	0800	1000	1200	1400
3-21	1	2.50	2.4	2.3	2.1	2.3	2.2
	2	0.50	0.50	0.50	0.50	0.50	0.50
	3	0.50	0.50	0.50	0.50	0.50	0.50
	4	0.50	0.50	0.50	0.50	0.50	0.50
3-22	1	1.25	1.25	1.25	1.25	1.25	1.25
	2	0.25	0.25	0.25	0.25	0.25	0.25
	3	0.25	0.25	0.25	0.25	0.25	0.25
	4	0.25	0.25	0.25	0.25	0.25	0.25
3-23	1	0.625	0.62	0.65	0.65	–	0.65
	2	0.125	0.15	0.15	0.15	–	0.15
	3	0.125	0.15	0.15	0.15	–	0.15
	4	0.125	0.15	0.15	0.15	–	0.15
3-24	1	0	0	0	0	0	0
	2	0	0	0	0	0	0
	3	0	0	0	0	0	0
	4	0	0	0	0	0	0

TABLE 3-2

highly concentrated. Subsequent samples were titrated at least twice with a much more dilute reagent, greatly improving the certainty of the results.

Data taken during the first day showed one entirely unreasonable result. The 4th stage scrubber actually increased the concentration of chlorides in the samples. This was probably due to an improperly located steam sampling input on the scrubber outlet. Consequently, samples from the 4th stage scrubber were not taken after the first day. Plans to change the sampling points are in progress.

Scrubber efficiency is calculated as:

$$E = \frac{C\ in - C\ out}{C\ in}$$

where:

C in = average chloride concentration in steam entering scrubber

C out = chloride concentration in steam exiting scrubber

Scrubber efficiencies were calculated for each sample taken during each day. These efficiencies were then statistically combined to yield the mean and the standard deviation of the samples taken at each flowrate from that mean. The calculations are shown in Tables 3-3 through 3-5. The plots of each scrubber's efficiency versus wash water flowrates are shown in Figures 3-1 through 3-3.

STEAM SCRUBBER PERFORMANCE TESTS
— AVERAGED CHLORIDE CONCENTRATIONS IN ppm —

– 1ST STAGE –

DATE	TIME	WASH WATER FLOW RATE (gpm)	CHLORIDE CONCENTRATION (AVERAGED)		EFFICIENCY	DAILY AVG EFFICIENCY (±1 S.D.)
			IN	OUT		
3-21	0800	2.3	70.9	31.5	0.556	0.548 ± 0.237 (43%)
	0900	–	44.6	14.2	0.682	
	1000	2.1	42.0	33.1	0.212	
	1200	2.3	145.	37.4	0.742	
3-22	0800	1.25	75.0	30.6	0.592	0.528 ± 0.334 (63%)
	0900	–	70.3	26.1	0.629	
	1000	1.25	132.	23.5	0.822	
	1200	1.25	25.5	26.7	-0.047	
	1400	1.25	76.3	27.0	0.646	
3-23	0800	0.65	121.	22.8	0.812	0.465 ± 0.355 (76%)
	0900	–	46.3	28.1	0.393	
	1000	0.65	38.9	21.5	0.447	
	1200	–	69.8	24.8	0.645	
	1400	0.65	66.0	21.0	0.682	
	1500	–	23.0	27.3	-0.187	
3-24	0800	0	56.9	30.5	0.464	0.470 ± 0.340 (72%)
	0900	0	29.7	32.1	-0.081	
	1000	0	66.5	25.6	0.615	
	1200	0	37.0	18.0	0.514	
	1400	0	131.	21.3	0.837	

TABLE 3-3

STEAM SCRUBBER PERFORMANCE TESTS
— AVERAGED CHLORIDE CONCENTRATIONS IN ppm —

– 2ND STAGE –

DATE	TIME	WASH WATER FLOW RATE (gpm)	CHLORIDE CONCENTRATION (AVERAGED)		EFFICIENCY	DAILY AVG EFFICIENCY (±1 S.D.)
			IN	OUT		
3-21	0800	0.50	13.6	12.6	0.0735	0.173 ± 0.113 (65%)
	0900	–	25.2	21.5	0.147	
	1000	0.50	17.3	11.5	0.335	
	1200	0.50	18.9	16.3	0.138	
3-22	0800	0.25	18.7	12.4	0.337	0.278 ± 0.203 (73%)
	0900	–	13.9	5.59	0.598	
	1000	0.25	12.4	10.7	0.137	
	1200	0.25	13.2	12.1	0.0833	
	1400	0.25	15.2	11.6	0.237	
3-23	0800	0.15	12.3	10.4	0.155	0.225 ± 0.057 (26%)
	0900	–	14.5	11.4	0.214	
	1000	0.15	15.1	11.4	0.245	
	1200	–	14.0	11.6	0.171	
	1400	0.15	13.3	9.97	0.250	
	1500	–	17.3	11.9	0.312	
3-24	0800	0	16.4	15.0	0.0854	0.224 ± 0.186 (83%)
	0900	0	11.6	10.5	0.0948	
	1000	0	11.5	10.5	0.0870	
	1200	0	16.2	9.87	0.391	
	1400	0	18.0	9.72	0.460	

TABLE 3-4

STEAM SCRUBBER PERFORMANCE TESTS
— AVERAGED CHLORIDE CONCENTRATIONS IN ppm —

– 3RD STAGE –

DATE	TIME	WASH WATER FLOW RATE (gpm)	CHLORIDE CONCENTRATION (AVERAGED)		EFFICIENCY	DAILY AVG EFFICIENCY (±1 S.D.)
			IN	OUT		
3-21	0800	0.50	23.6	11.0	0.534	0.423 ± 0.100 (24%)
	0900	–	26.2	14.2	0.458	
	1000	0.50	14.2	10.0	0.296	
	1200	0.50	22.0	13.1	0.405	
3-22	0800	0.25	17.9	8.72	0.513	0.316 ± 0.233 (74%)
	0900	–	17.3	6.65	0.616	
	1000	0.25	10.1	8.77	0.132	
	1200	0.25	7.94	7.10	0.106	
	1400	0.25	11.3	8.89	0.213	
3-23	0800	0.15	14.6	8.32	0.430	0.254 ± 0.400 (157%)
	0900	–	34.6	8.66	0.750	
	1000	0.15	9.27	9.72	-0.049	
	1200	–	9.04	11.2	-0.234	
	1400	0.15	22.5	8.55	0.619	
	1500	–	9.76	9.68	0.009	
3-24	0800	0	12.9	9.58	0.254	0.385 ± 0.214 (56%)
	0900	0	11.5	8.34	0.275	
	1000	0	12.1	10.0	0.174	
	1200	0	19.2	8.53	0.555	
	1400	0	28.5	9.45	0.668	

TABLE 3-5

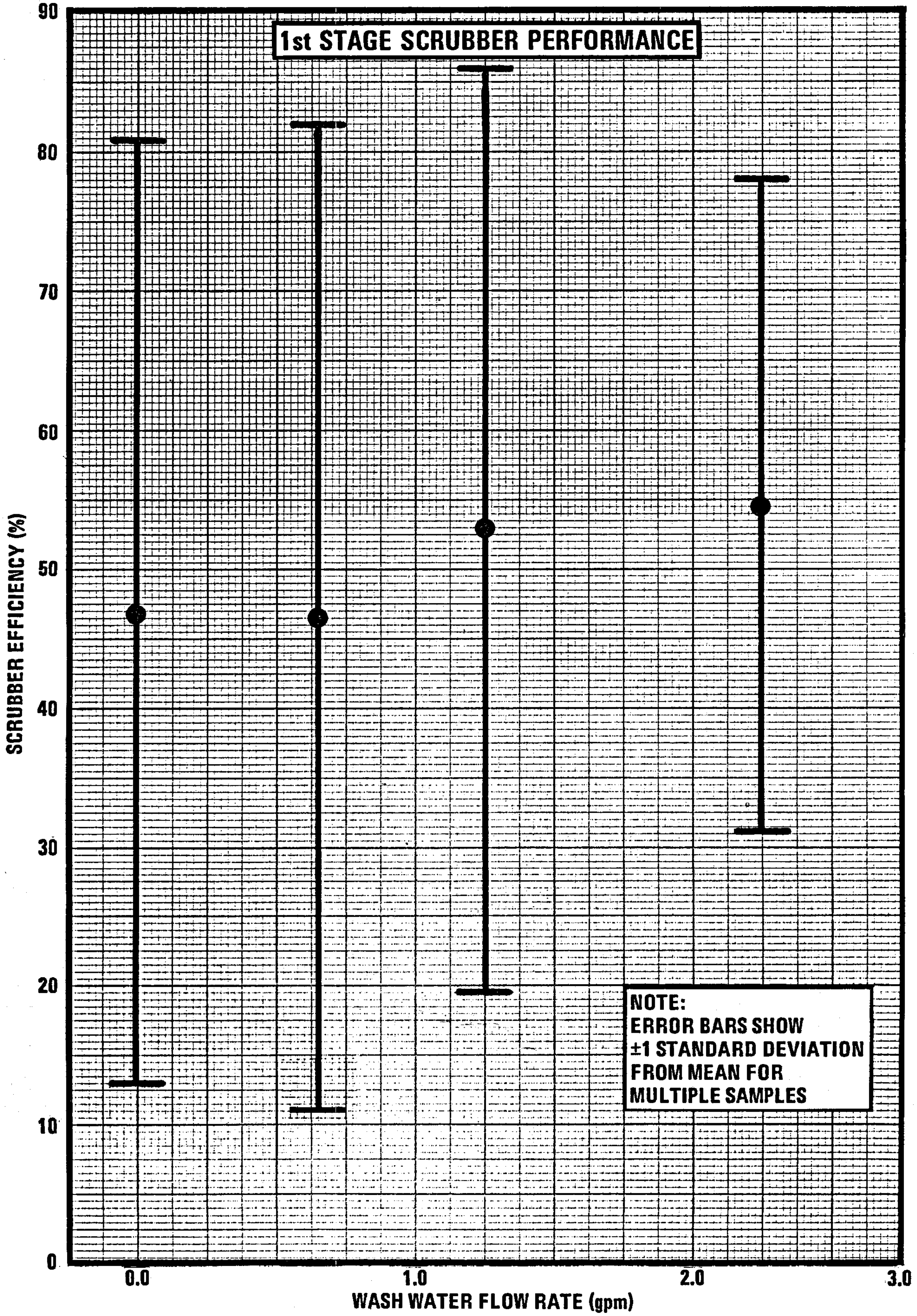

1st STAGE SCRUBBER PERFORMANCE
SCRUBBER EFFICIENCY (%)
90
80
70
60
50
40
30
20
10
0
0.0
1.0
2.0
3.0
WASH WATER FLOW RATE (gpm)
NOTE:
ERROR BARS SHOW
±1 STANDARD DEVIATION
FROM MEAN FOR
MULTIPLE SAMPLES

FIGURE 3-1

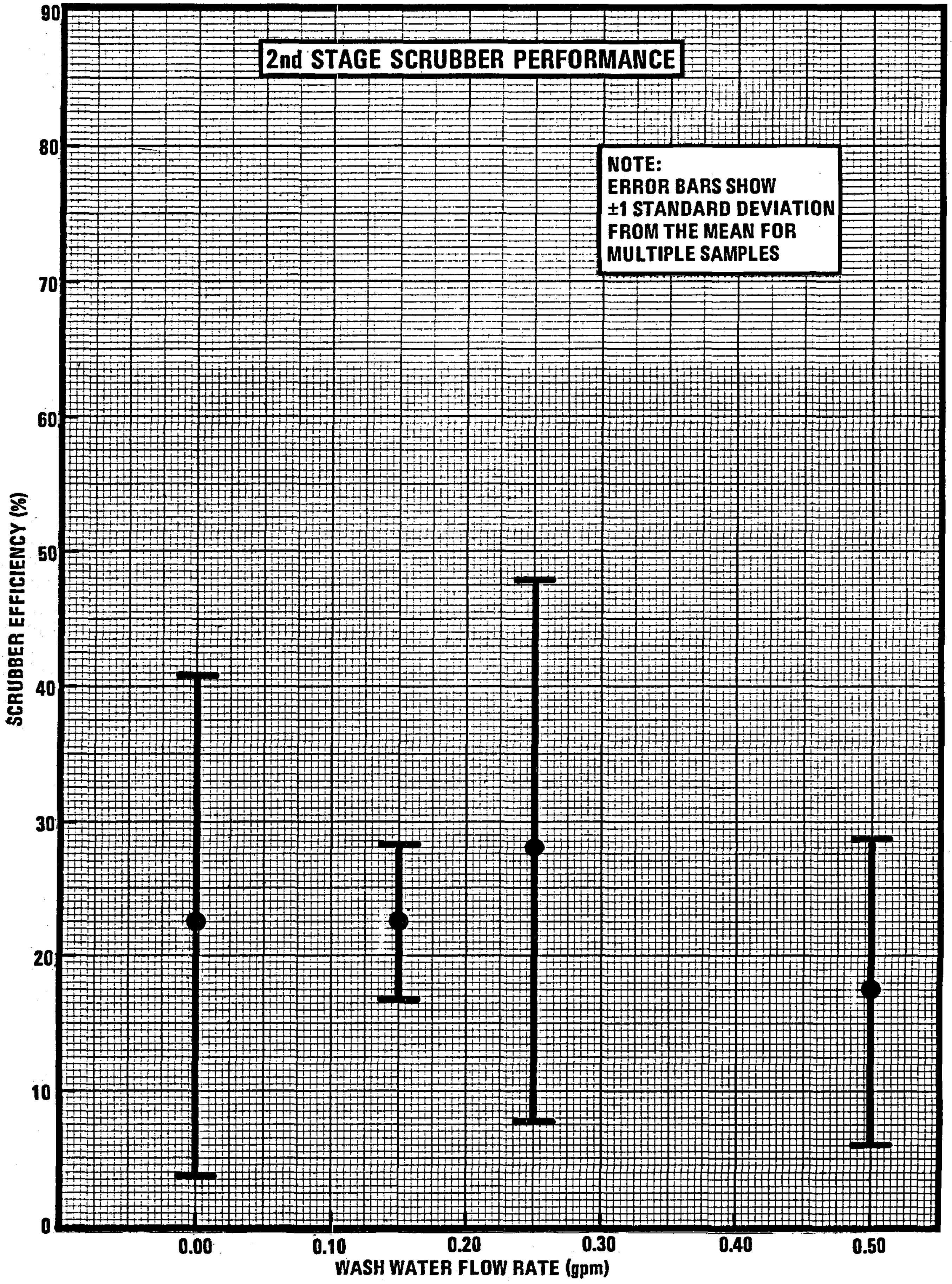

2nd STAGE SCRUBBER PERFORMANCE
NOTE:
ERROR BARS SHOW
±1 STANDARD DEVIATION
FROM THE MEAN FOR
MULTIPLE SAMPLES
SCRUBBER EFFICIENCY (%)
90
80
70
60
50
40
30
20
10
0
0.00
0.10
0.20
0.30
0.40
0.50
WASH WATER FLOW RATE (gpm)

FIGURE 3-2

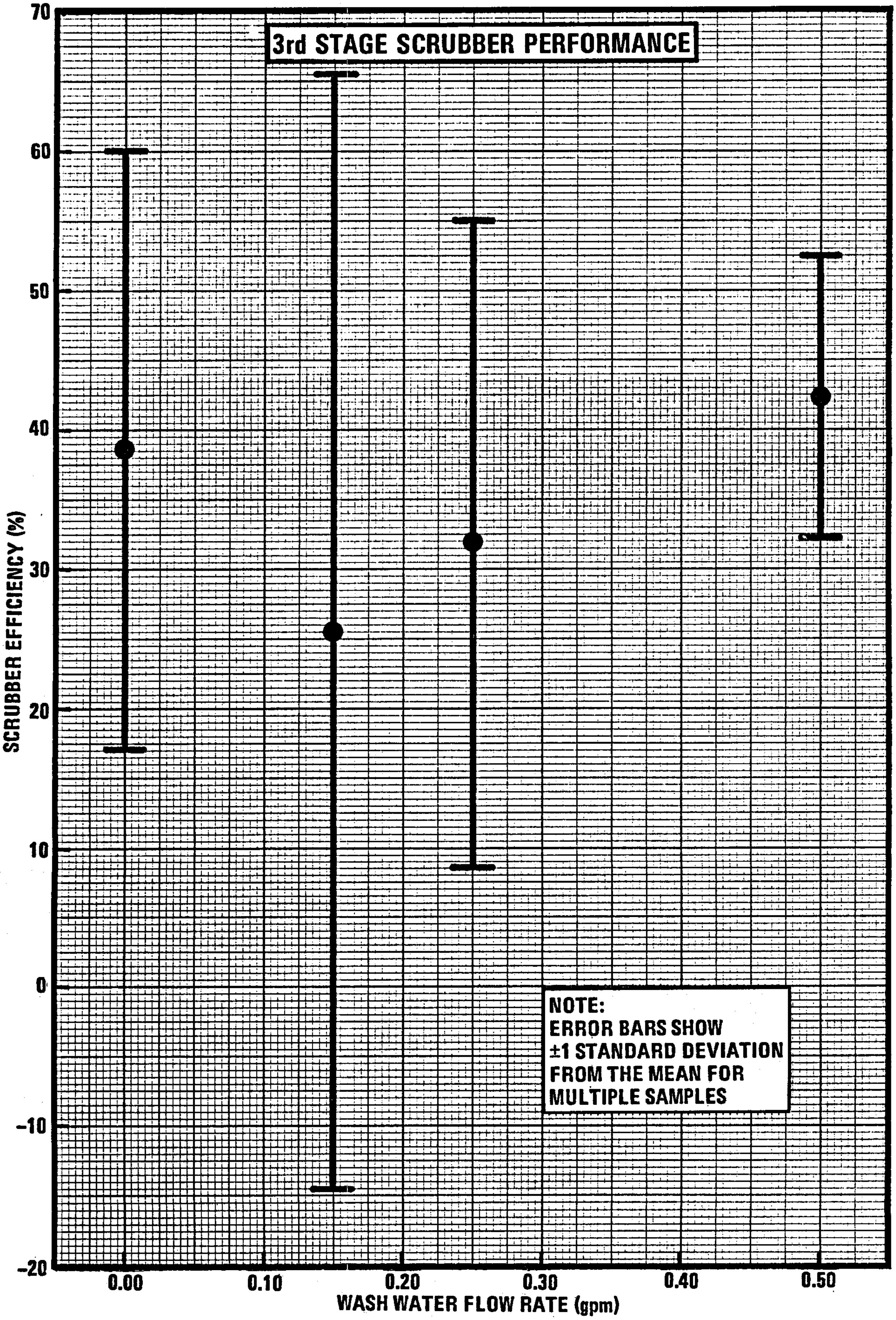

3rd STAGE SCRUBBER PERFORMANCE
SCRUBBER EFFICIENCY (%)
70
60
50
40
30
20
10
0
-10
-20
0.00
0.10
0.20
0.30
0.40
0.50
WASH WATER FLOW RATE (gpm)
NOTE:
ERROR BARS SHOW
±1 STANDARD DEVIATION
FROM THE MEAN FOR
MULTIPLE SAMPLES

FIGURE 3-3

3.4 Conclusions:

Tables 3-2 through 3-5 and Figures 3-1 through 3-3 show that there are very large uncertainties in the measurements of scrubber efficiency at all wash water flowrates. The statistical spread of this data is so large that valid conclusions are difficult to draw. In addition, the uncertainty in the determination of efficiency may be much larger than is shown on the graphs. The assumption that chloride ion concentrations are equivalent to total dissolved solids carryover is only an approximation, as discussed earlier.

For future tests, the sampling apparatus will be modified. One inch carbon steel lines (some quite lengthy) were used to draw the samples. Corrosion products from these lines may have affected the accuracy of the data. Thus the sampling ports also would have contributed to the widely varying results.

Most importantly the brine carryover into the steam is not constant. Brine surging in the well flows cause carry over of liquid droplets to be entrained in the steam leaving the separator. This is evidenced by the widely varying chloride levels in the steam entering the scrubber. If a steam sample is taken at the scrubber inlet during one of these periods, and the sample at the scrubber outlet is not taken during one, vastly different levels of removal efficiencies could be observed. Consequently, the validity of any single data point taken during this test is questionable.

When it is determined that the scrubber tests do need to be performed again, the entire test procedure shall be reviewed. The need for a constant level of contamination in the steam entering the scrubber will be analyzed, the steam sampling techniques will be improved and the number of samples taken will be sufficient for proper statistical analysis.

4.0 SYSTEMS CHEMISTRY

4.1 Steam

Solids carried over with the steam can adversely influence heat exchanger or turbine efficiency through deposition on the heat exchanger or turbine blade surfaces. To estimate the degree of solids carried over, samples of geothermal steam leaving each separator and each scrubber were taken. The pH, electrical conductivity, total dissolved solids, chloride, sodium, calcium, and iron content of these samples were measured. These measurements are summarized in Figures 4-1 to 4-10 and are discussed below.

4.1.1 ph

The pH of the steam increased from slightly acidic (6.0 to 6.5) for the first stage steam to significantly alkaline (9.5 to 10.0) for the third stage steam. The pH of the fourth stage steam was slightly acidic (6.5). These steam pH trends have been observed during the entire operating history of the GLEF and are attributed to changes in the dissolved gas species.

The concentration of these dissolved gases does not change as the steam passes through an essentially mechanical scrubber so the steam pH is not materially changed by this process. The scrubber removes a portion of the entrained droplets of geothermal brine from the steam and this effectiveness is discussed in the following sections.

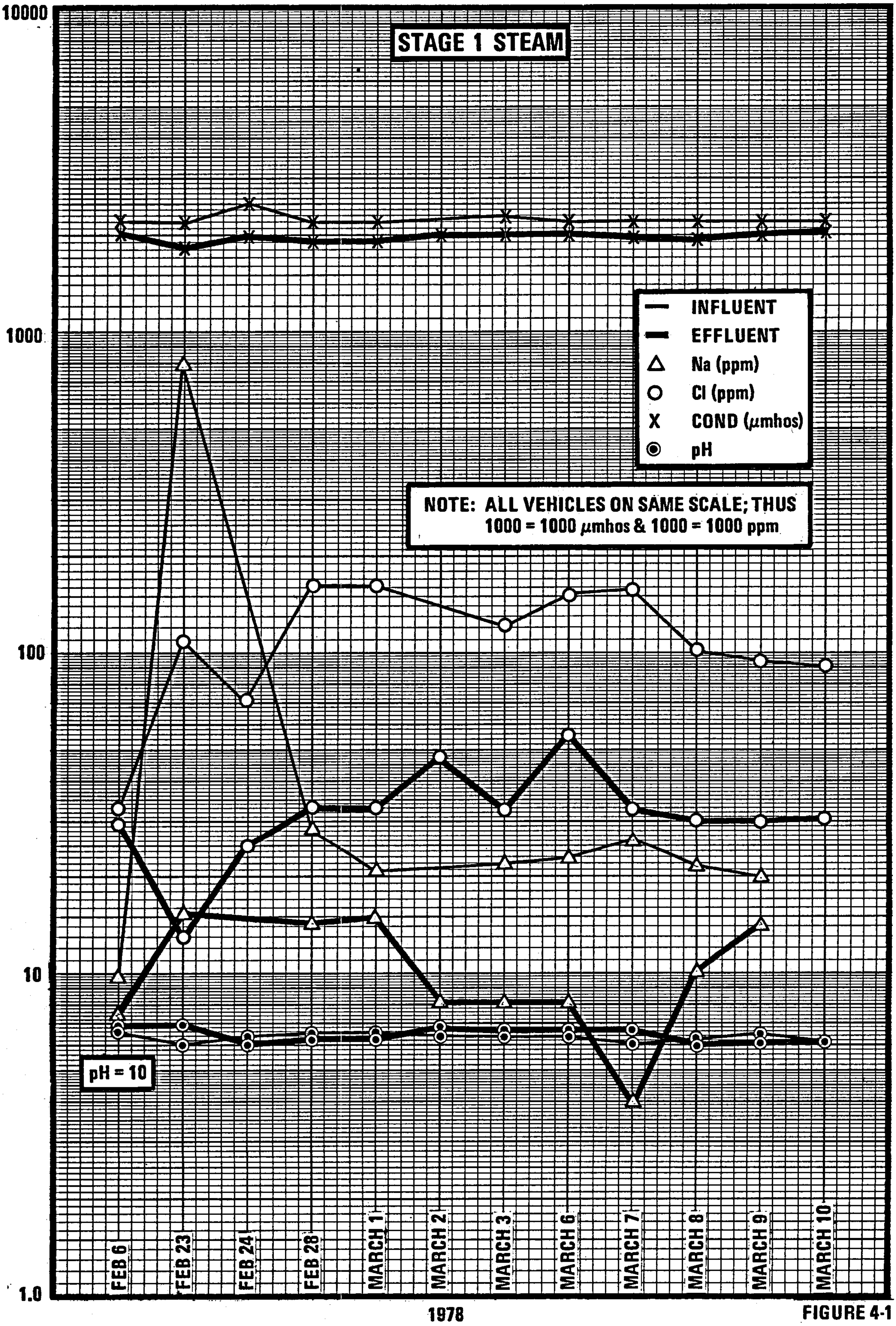

STAGE 1 STEAM
10000
1000
100
10
1.0
INFLUENT
EFFLUENT
Na (ppm)
Cl (ppm)
COND (µmhos)
pH
NOTE: ALL VEHICLES ON SAME SCALE; THUS 1000 = 1000 µmhos & 1000 = 1000 ppm
pH = 10
FEB 6
FEB 23
FEB 24
FEB 28
MARCH 1
MARCH 2
MARCH 3
MARCH 6
MARCH 7
MARCH 8
MARCH 9
MARCH 10
1978

FIGURE 4-1

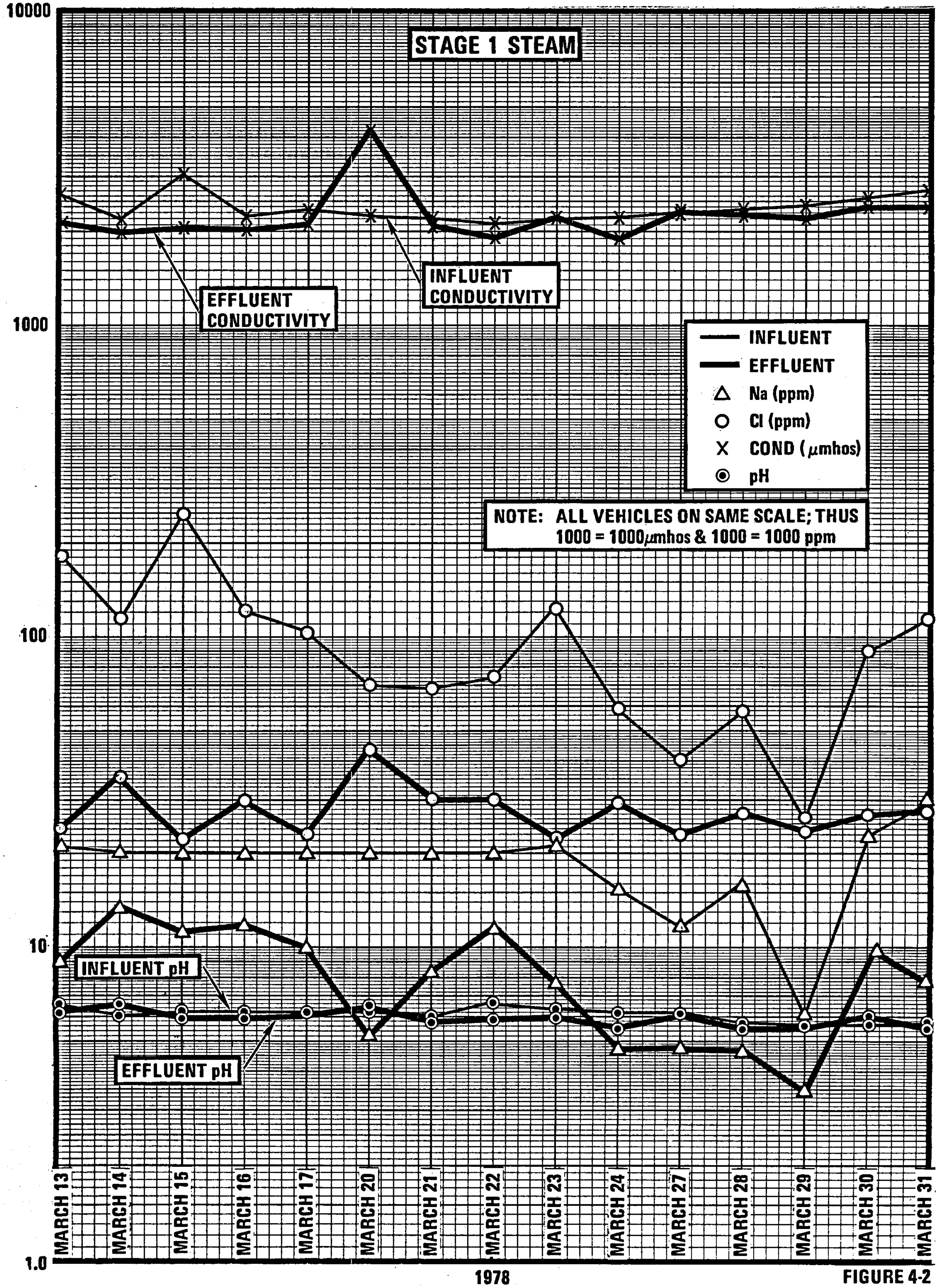

STAGE 1 STEAM
10000
1000
100
10
1.0
EFFLUENT CONDUCTIVITY
INFLUENT CONDUCTIVITY
INFLUENT
EFFLUENT
△ Na (ppm)
○ Cl (ppm)
X COND (μmhos)
◉ pH
NOTE: ALL VEHICLES ON SAME SCALE; THUS 1000 = 1000μmhos & 1000 = 1000 ppm
INFLUENT pH
EFFLUENT pH
MARCH 13
MARCH 14
MARCH 15
MARCH 16
MARCH 17
MARCH 20
MARCH 21
MARCH 22
MARCH 23
MARCH 24
MARCH 27
MARCH 28
MARCH 29
MARCH 30
MARCH 31
1978

FIGURE 4-2

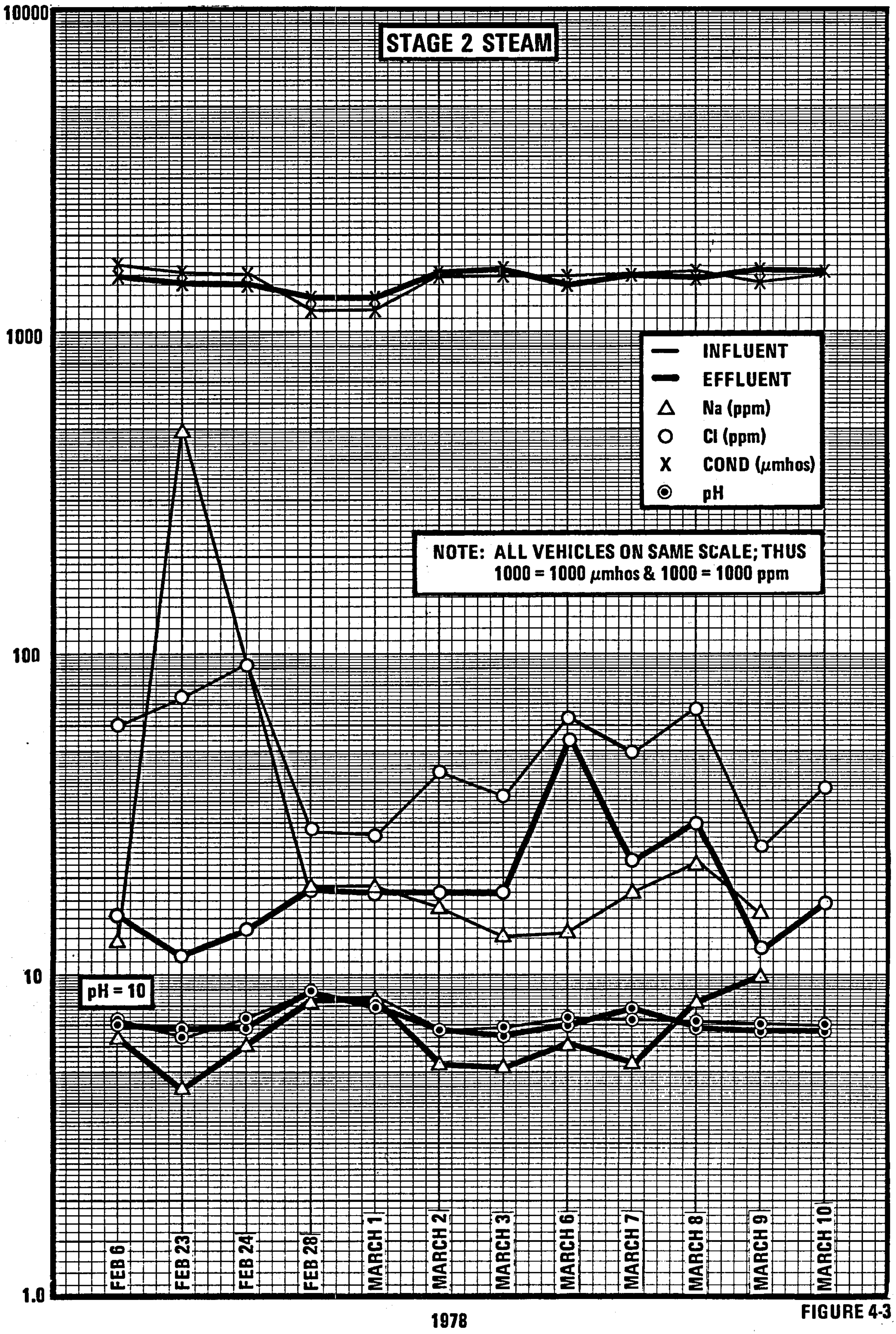

STAGE 2 STEAM
10000
1000
100
10
1.0
INFLUENT
EFFLUENT
Na (ppm)
Cl (ppm)
COND (μmhos)
pH
NOTE: ALL VEHICLES ON SAME SCALE; THUS
1000 = 1000 μmhos & 1000 = 1000 ppm
pH = 10
FEB 6
FEB 23
FEB 24
FEB 28
MARCH 1
MARCH 2
MARCH 3
MARCH 6
MARCH 7
MARCH 8
MARCH 9
MARCH 10
1978

FIGURE 4-3

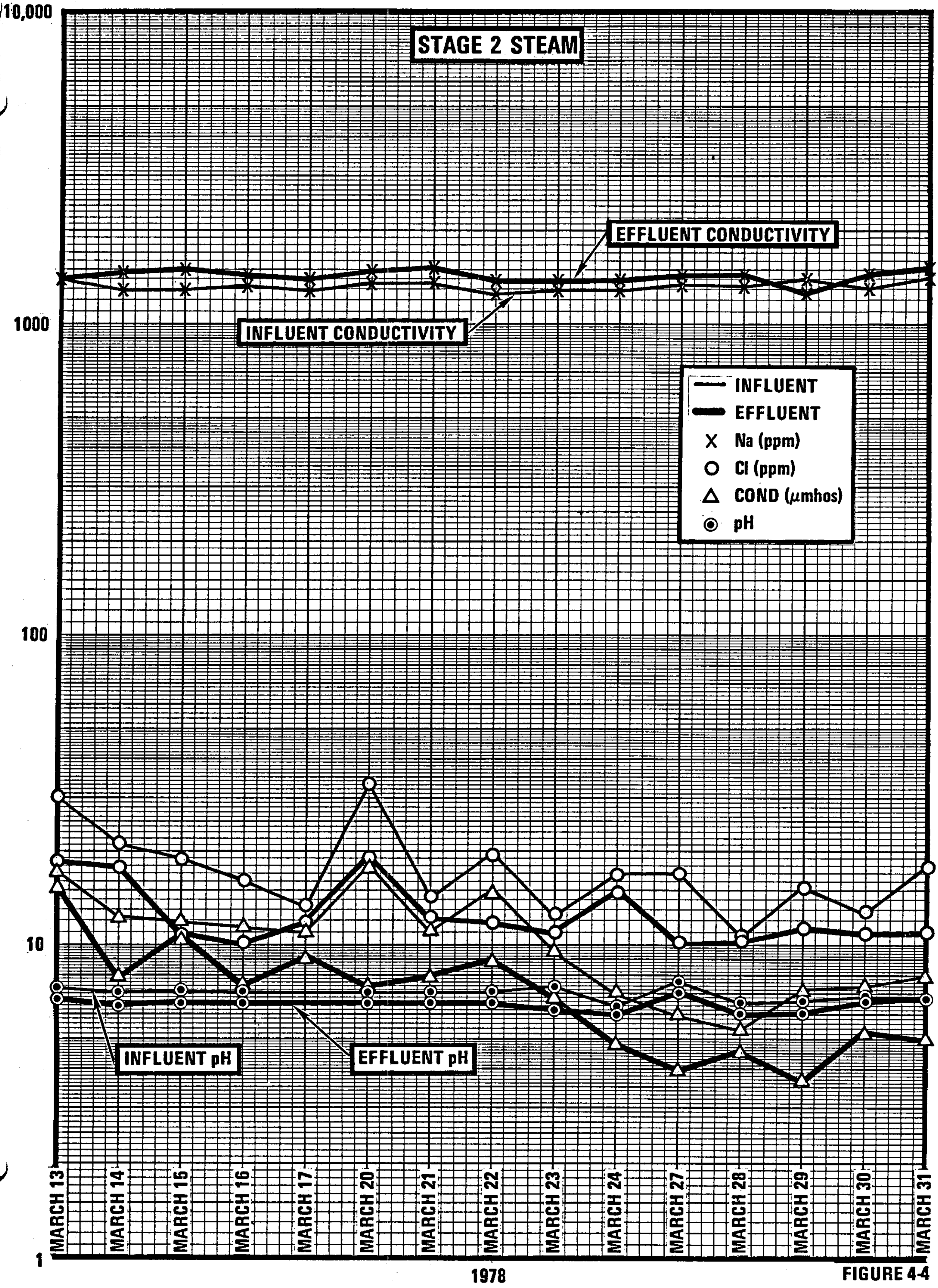
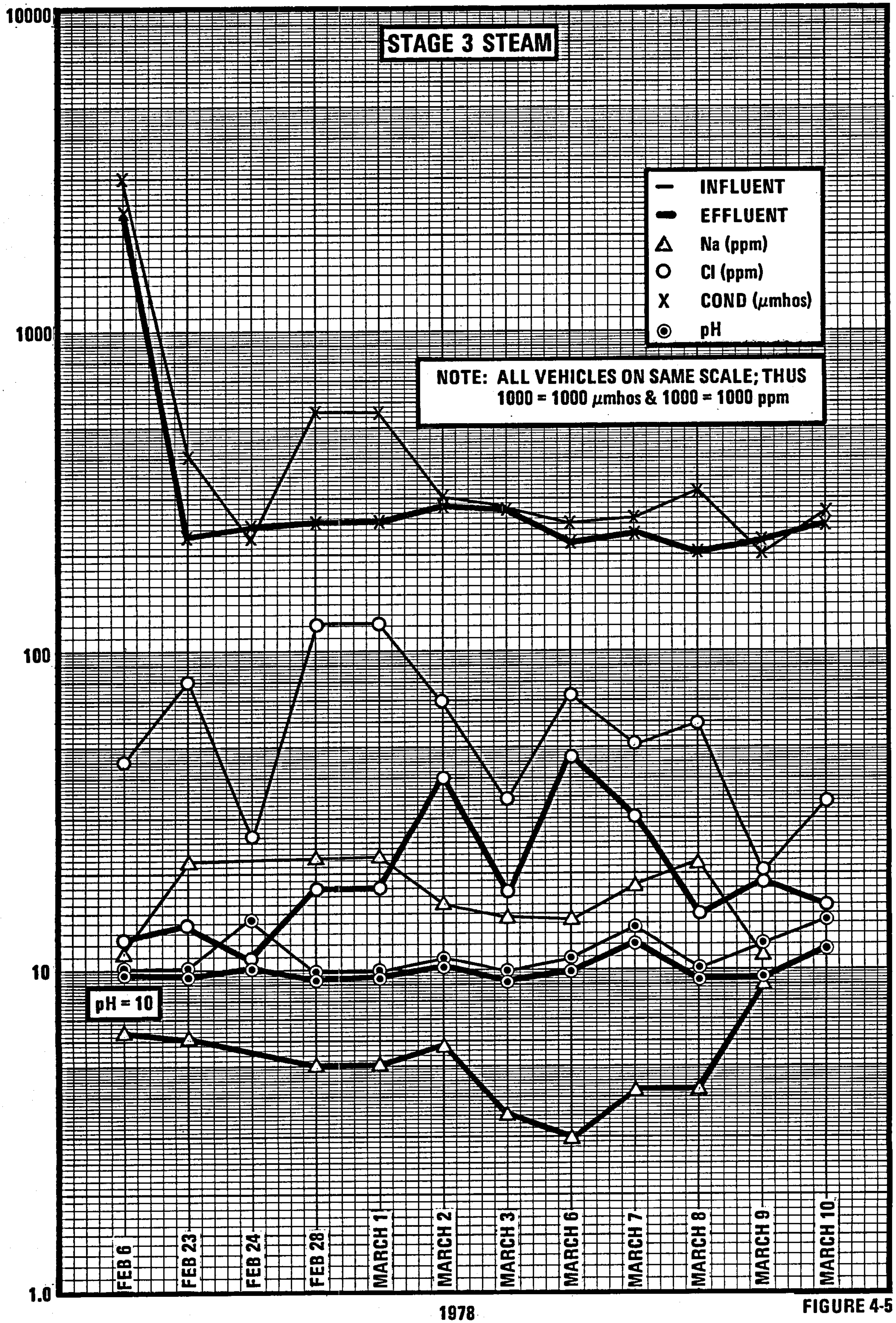

STAGE 2 STEAM
10,000
1000
100
10
1
EFFLUENT CONDUCTIVITY
INFLUENT CONDUCTIVITY
INFLUENT
EFFLUENT
X Na (ppm)
O Cl (ppm)
△ COND (μmhos)
◉ pH
INFLUENT pH
EFFLUENT pH
MARCH 13
MARCH 14
MARCH 15
MARCH 16
MARCH 17
MARCH 20
MARCH 21
MARCH 22
MARCH 23
MARCH 24
MARCH 27
MARCH 28
MARCH 29
MARCH 30
MARCH 31
1978

FIGURE 4-4



STAGE 3 STEAM
10000
1000
100
10
1.0
— INFLUENT
▬ EFFLUENT
△ Na (ppm)
○ Cl (ppm)
X COND (μmhos)
◉ pH
NOTE: ALL VEHICLES ON SAME SCALE; THUS 1000 = 1000 μmhos & 1000 = 1000 ppm
pH = 10
FEB 6
FEB 23
FEB 24
FEB 28
MARCH 1
MARCH 2
MARCH 3
MARCH 6
MARCH 7
MARCH 8
MARCH 9
MARCH 10
1978

FIGURE 4-5

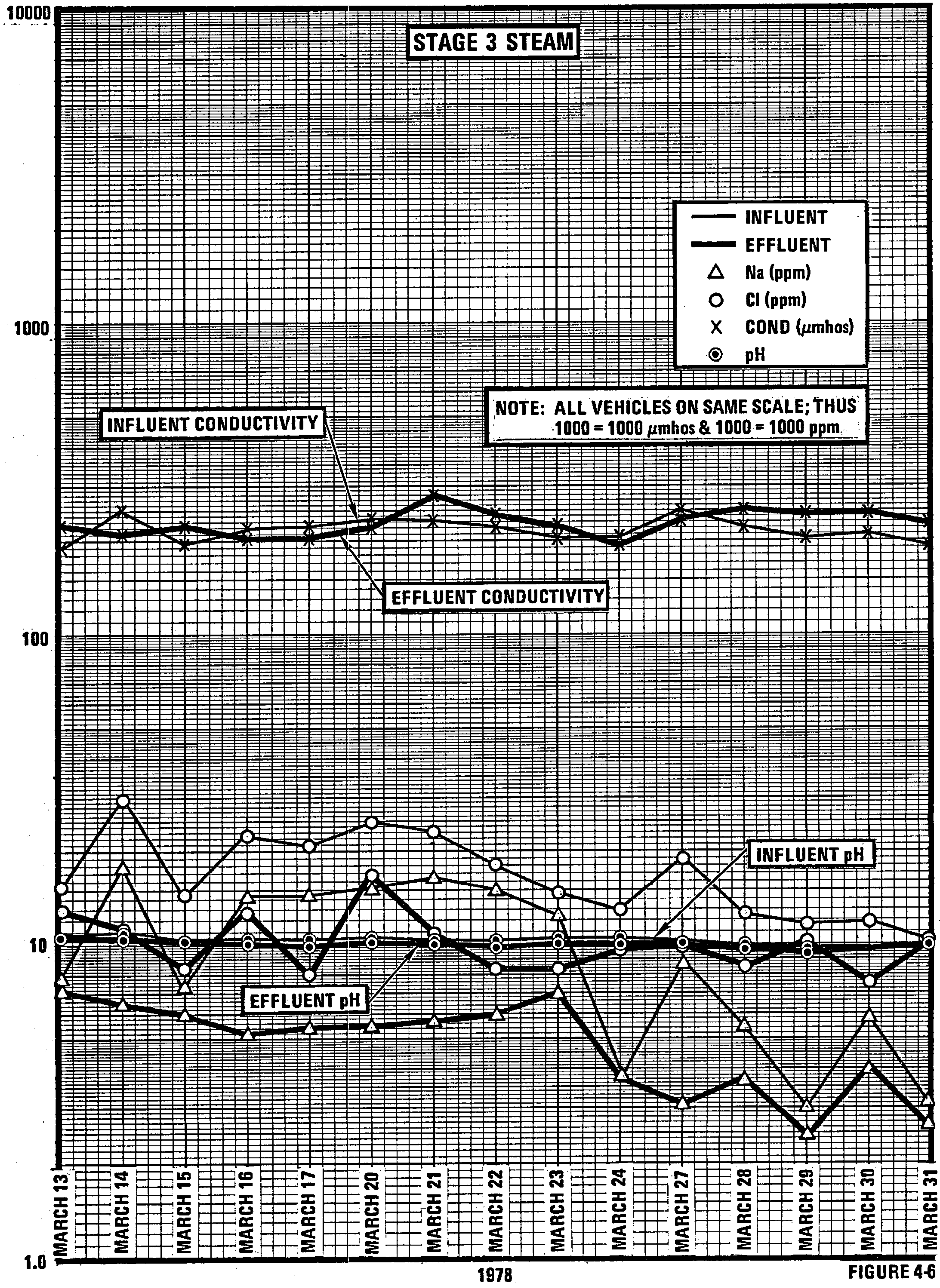

STAGE 3 STEAM
10000
1000
100
10
1.0
INFLUENT
EFFLUENT
△ Na (ppm)
○ Cl (ppm)
X COND (μmhos)
◉ pH
NOTE: ALL VEHICLES ON SAME SCALE; THUS 1000 = 1000 μmhos & 1000 = 1000 ppm
INFLUENT CONDUCTIVITY
EFFLUENT CONDUCTIVITY
INFLUENT pH
EFFLUENT pH
MARCH 13
MARCH 14
MARCH 15
MARCH 16
MARCH 17
MARCH 20
MARCH 21
MARCH 22
MARCH 23
MARCH 24
MARCH 27
MARCH 28
MARCH 29
MARCH 30
MARCH 31
1978

FIGURE 4-6

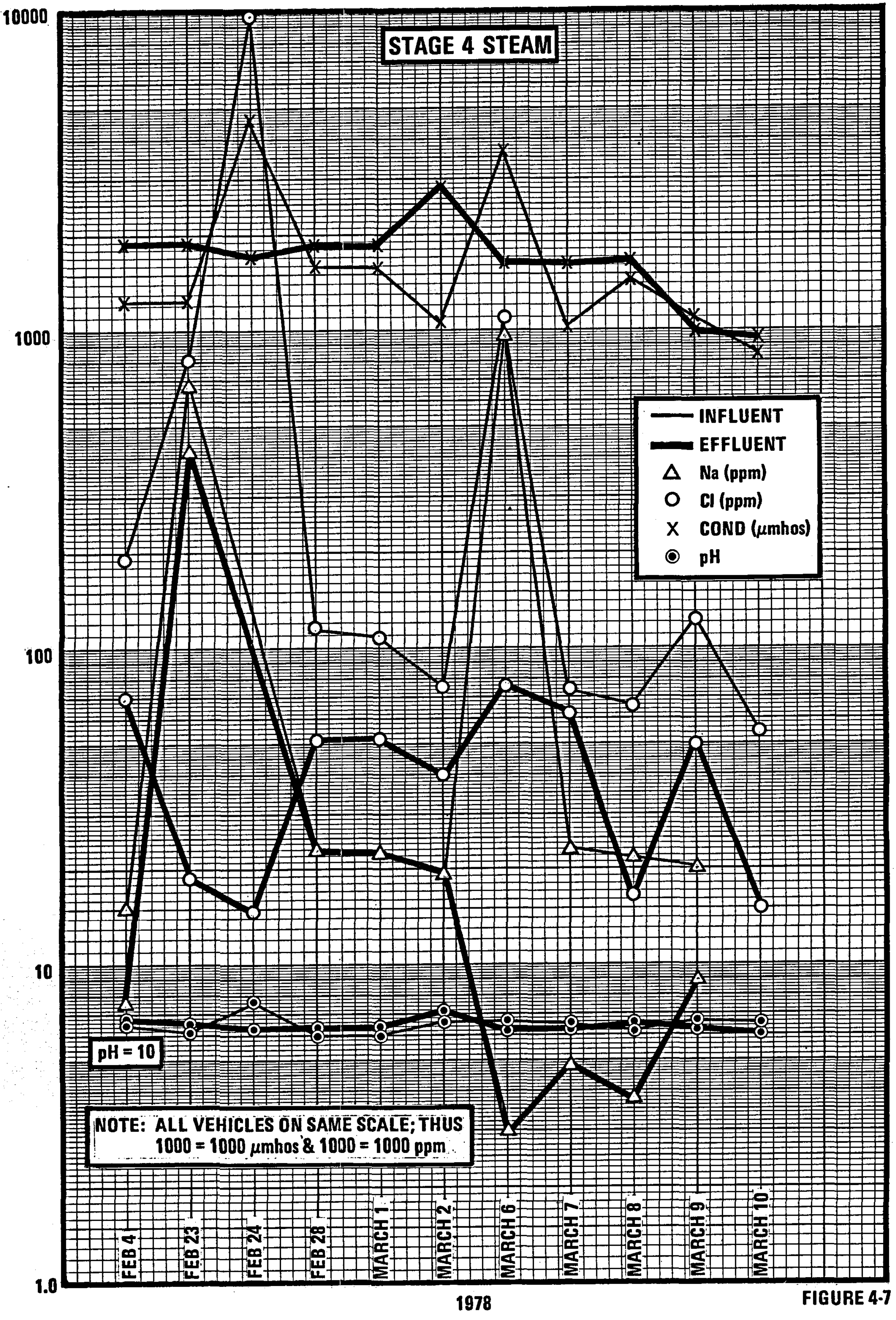

STAGE 4 STEAM
10000
1000
100
10
1.0
INFLUENT
EFFLUENT
△ Na (ppm)
○ Cl (ppm)
X COND (μmhos)
◉ pH
pH = 10
NOTE: ALL VEHICLES ON SAME SCALE; THUS 1000 = 1000 μmhos & 1000 = 1000 ppm
FEB 4
FEB 23
FEB 24
FEB 28
MARCH 1
MARCH 2
MARCH 6
MARCH 7
MARCH 8
MARCH 9
MARCH 10
1978

FIGURE 4-7

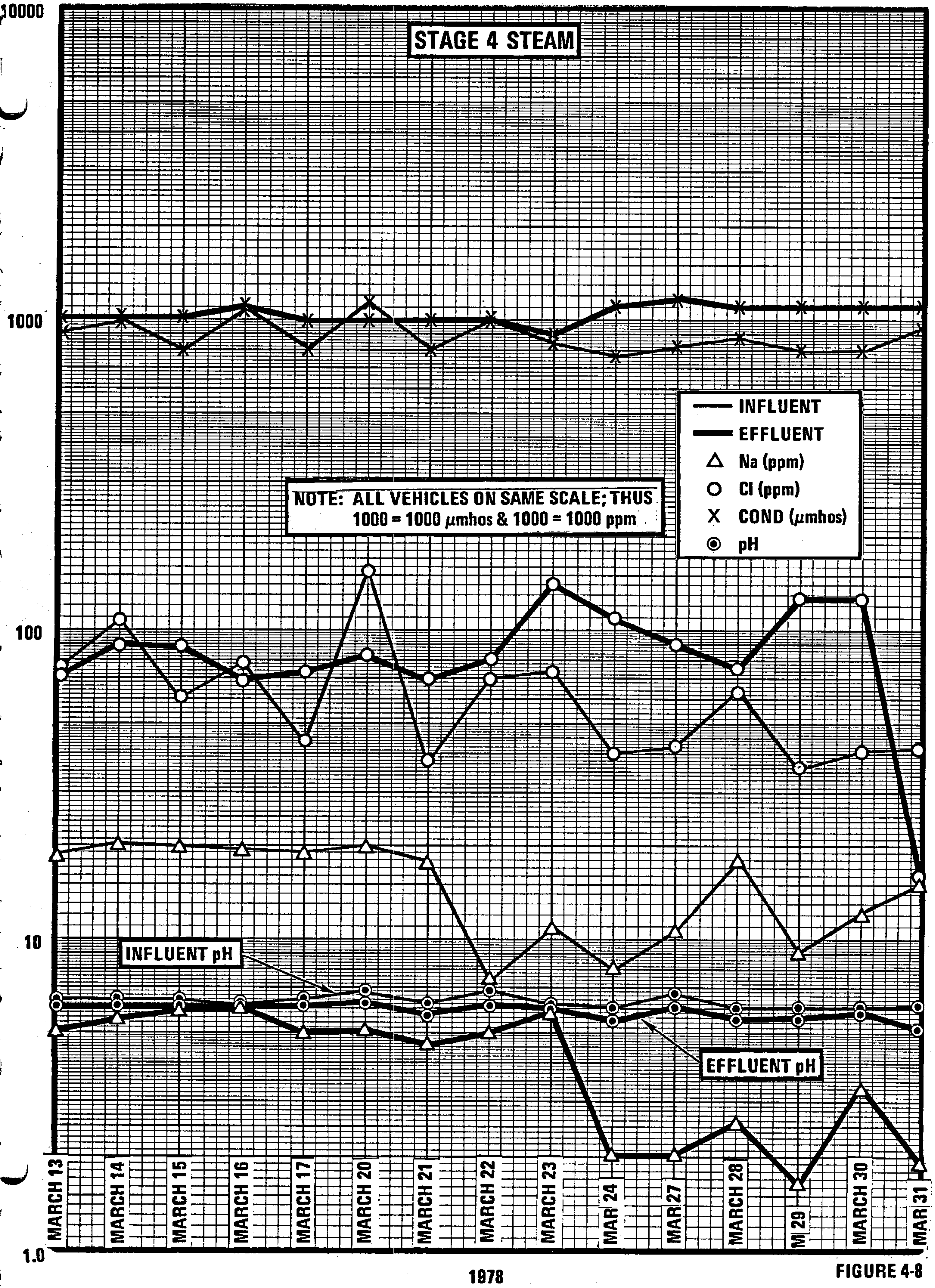
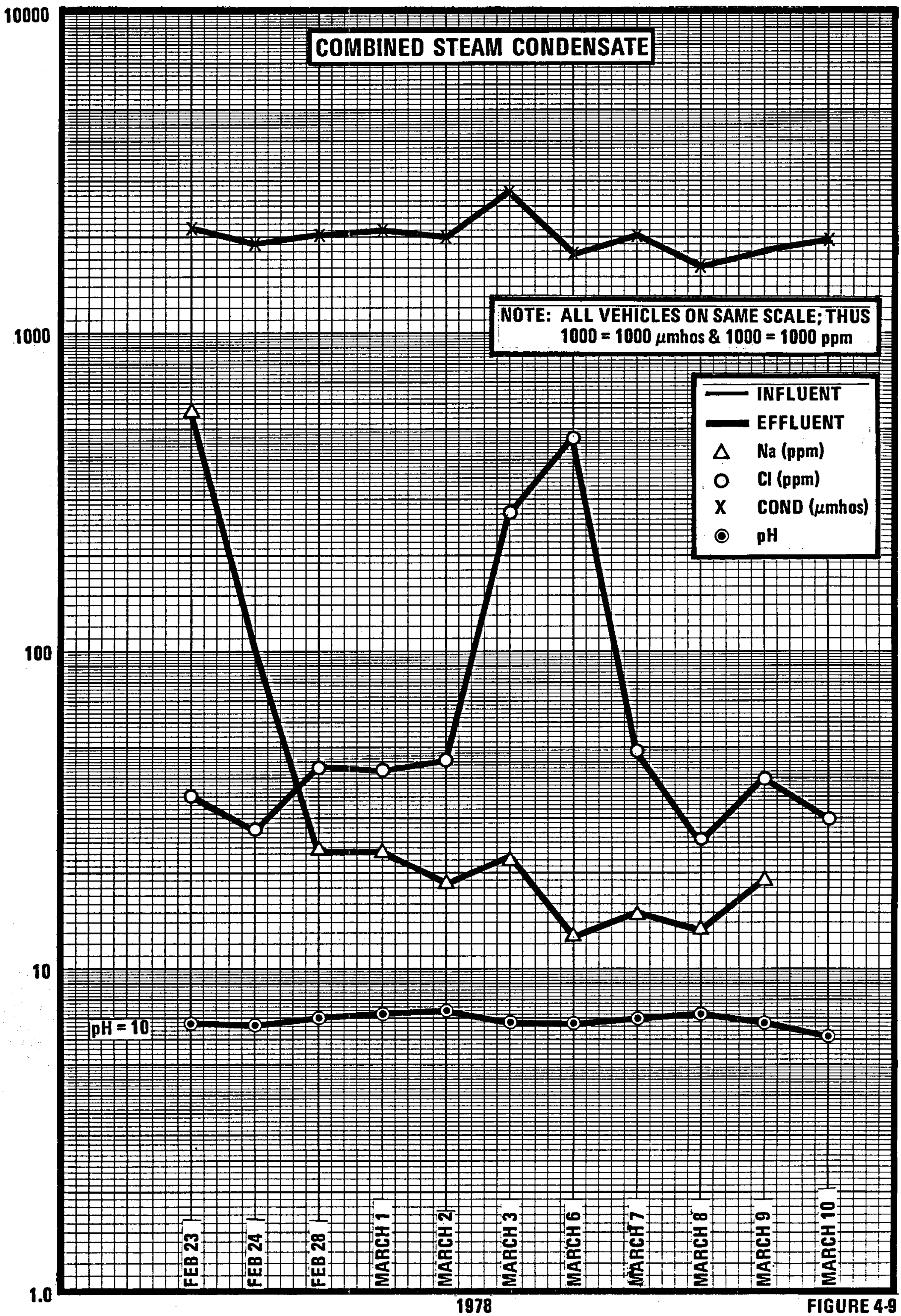

STAGE 4 STEAM
10000
1000
100
10
1.0
INFLUENT
EFFLUENT
Na (ppm)
Cl (ppm)
COND (µmhos)
pH
NOTE: ALL VEHICLES ON SAME SCALE; THUS 1000 = 1000 µmhos & 1000 = 1000 ppm
INFLUENT pH
EFFLUENT pH
MARCH 13
MARCH 14
MARCH 15
MARCH 16
MARCH 17
MARCH 20
MARCH 21
MARCH 22
MARCH 23
MAR 24
MAR 27
MARCH 28
M 29
MARCH 30
MAR 31
1978

FIGURE 4-8



10000
1000
100
10
1.0
COMBINED STEAM CONDENSATE
NOTE: ALL VEHICLES ON SAME SCALE; THUS 1000 = 1000 μmhos & 1000 = 1000 ppm
INFLUENT
EFFLUENT
△ Na (ppm)
○ Cl (ppm)
X COND (μmhos)
◉ pH
pH = 10
FEB 23
FEB 24
FEB 28
MARCH 1
MARCH 2
MARCH 3
MARCH 6
MARCH 7
MARCH 8
MARCH 9
MARCH 10
1978

FIGURE 4-9

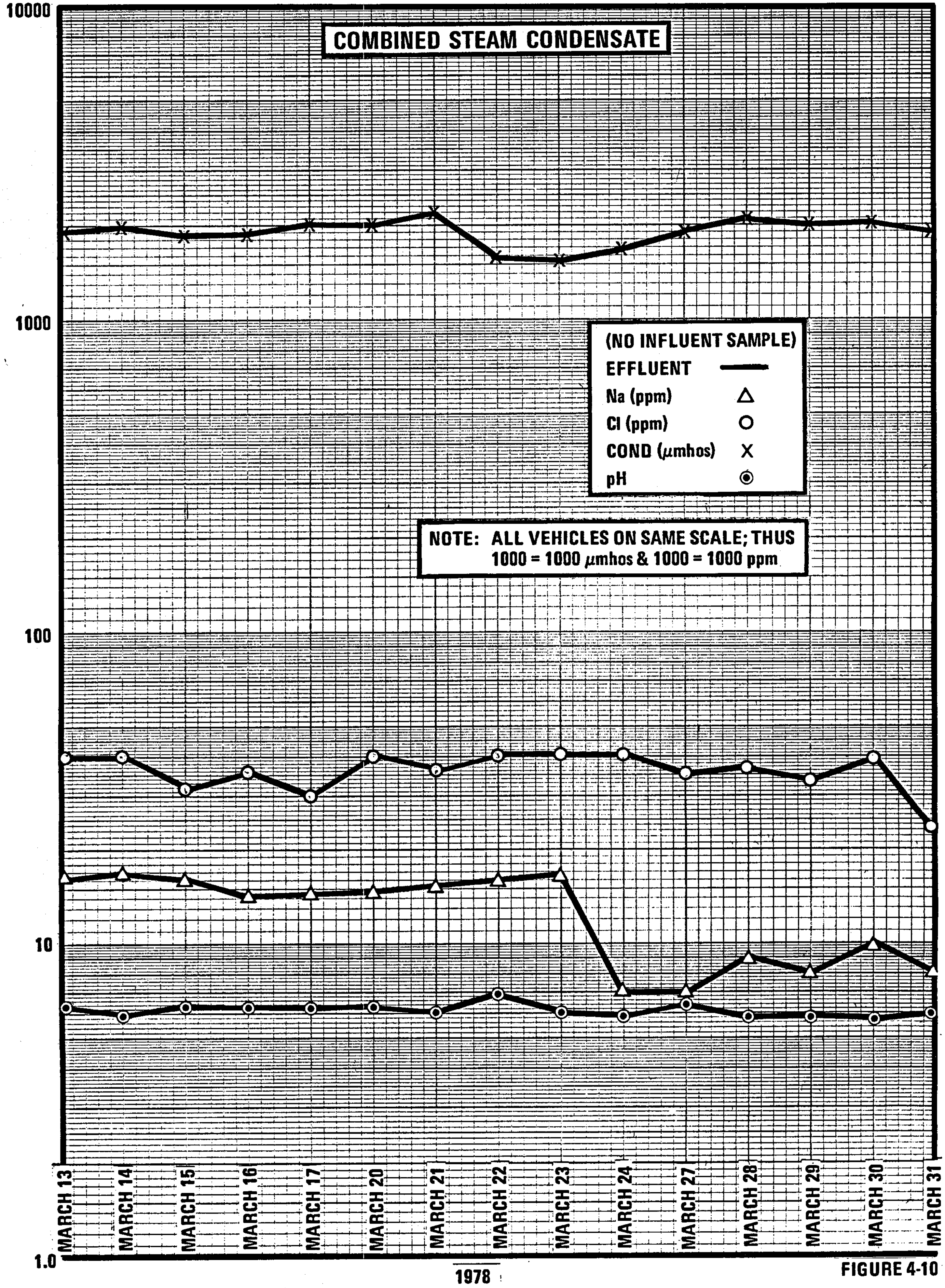

COMBINED STEAM CONDENSATE
(NO INFLUENT SAMPLE)
EFFLUENT
Na (ppm) △
Cl (ppm) ○
COND (μmhos) X
pH ⊙
NOTE: ALL VEHICLES ON SAME SCALE; THUS 1000 = 1000 μmhos & 1000 = 1000 ppm
10000
1000
100
10
1.0
MARCH 13
MARCH 14
MARCH 15
MARCH 16
MARCH 17
MARCH 20
MARCH 21
MARCH 22
MARCH 23
MARCH 24
MARCH 27
MARCH 28
MARCH 29
MARCH 30
MARCH 31
1978

FIGURE 4-10

4.1.2 Conductivity

The electrical conductivity of the geothermal steam is also strongly influenced by dissolved gases (carbon dioxide and ammonia). Thus, its value is high in the first stage where most of the gas, particularly carbon dioxide, is evolved. The conductivity of steam from the second and third stage is lower due to the smaller amount of gases present. The condensate from the second and third stages are reintroduced into the fourth stage resulting in an increase in the conductivity of the fourth stage steam.

This conductivity variation from stage to stage follows the same trends as the pH (see 4.1.1). This would indicate the conductivity of the geothermal steam is strongly dependent on the specie and amount of noncondensible gases present.

4.1.3 Chloride

Since the geothermal brine is almost entirely a chloride brine, the chloride concentration in the geothermal steam is probably indicative of scrubber and separator effectiveness. If they are effective, the chloride level in the geothermal steam will be low.

In addition to the metal chlorides, ammonium chloride can also exist in the steam. Thus the chloride level can serve as an indication of total ionic species in the steam.

The chloride values fluctuated greatly during the first 30 days of the test. These variations appear to be caused by operating instabilities in the plant. As plant operation presumably stablized during the second 30 days so did the steam chloride levels.

4.1.4 Sodium

Sodium is the major cation in the geothermal brine and thus is also a useful indicator of separator and scrubber efficiency. Except for evaporation, any droplet of liquid carried over with the steam should hold the same amount of sodium that is in the brine. Sodium compounds are not expected to be volatile at the GLEF temperatures so the sodium concentration in the geothermal steam should be a good indicator of brine carryover.

Some fluctions were also seen in the sodium levels in the geothermal brines during the first 30 days. This is also indicative of operating problems during this period, particularly in the fourth stage. Stabilization at a lower level was observed during the second 30 days.

With one exception, the fourth stage on February 23rd, the scrubbers were effective in substantually reducing the sodium concentration in the steam. Reductions of as much as an order of magnitude were observed. This presumedly reflects a comparable reduction in the brine droplets carried over with the steam.

4.1.5 Calcium

Calcium is also a constituent of the brine and has been measured in the steam. The values are shown in Figures 4-11 through 4-13 for the first 3 stages. The influent values are generally higher than the effluent values, and only small differences are observed between stages. The calcium levels in the fourth stage combined condensate are similar to the first three stages and are not presented here.

4.1.6 Iron

Iron was also measured in the steam. Although iron is not a major constituent of the brine, it is present in measurable amounts in the steam. For example the values in the 1st stage range from .8 to 0.3 ppm. Iron levels in the effluent sometimes are greater than the influent. These erratic values and higher iron levels in the effluent indicate the vessels and pipes may also be a source of iron in the steam. See Figures 4-14 through 4-16 for these values and calcium.

4.2 Brine

Composition of the brine has been measured through out the plant. The changes in concentration can be attributed to liquid lost as steam. The total solids and conductivity also agree well with the values of sodium, calcium, potassium and chloride, which comprise the major part of the brine.

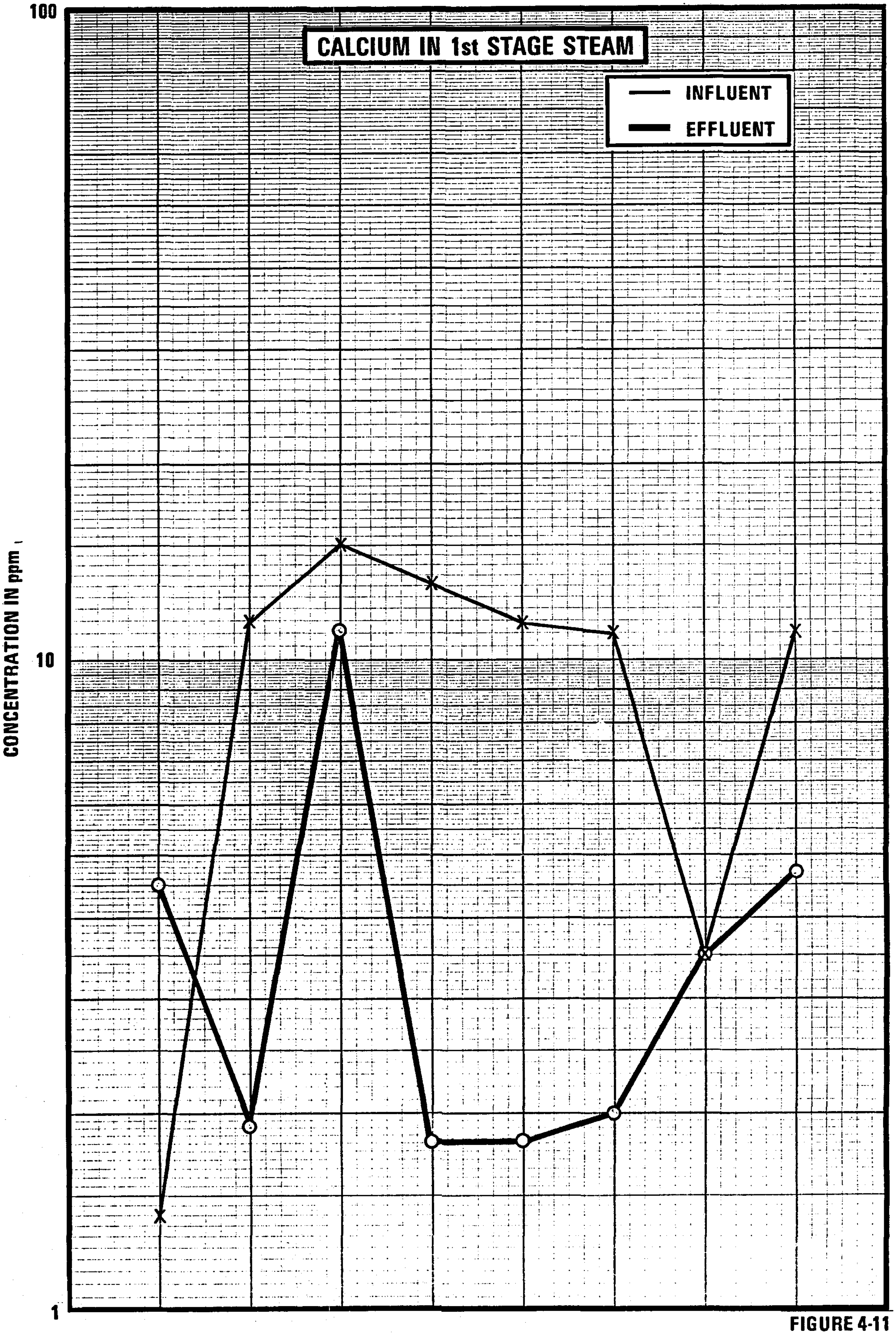

100
CALCIUM IN 1st STAGE STEAM
INFLUENT
EFFLUENT
CONCENTRATION IN ppm
10
1

FIGURE 4-11

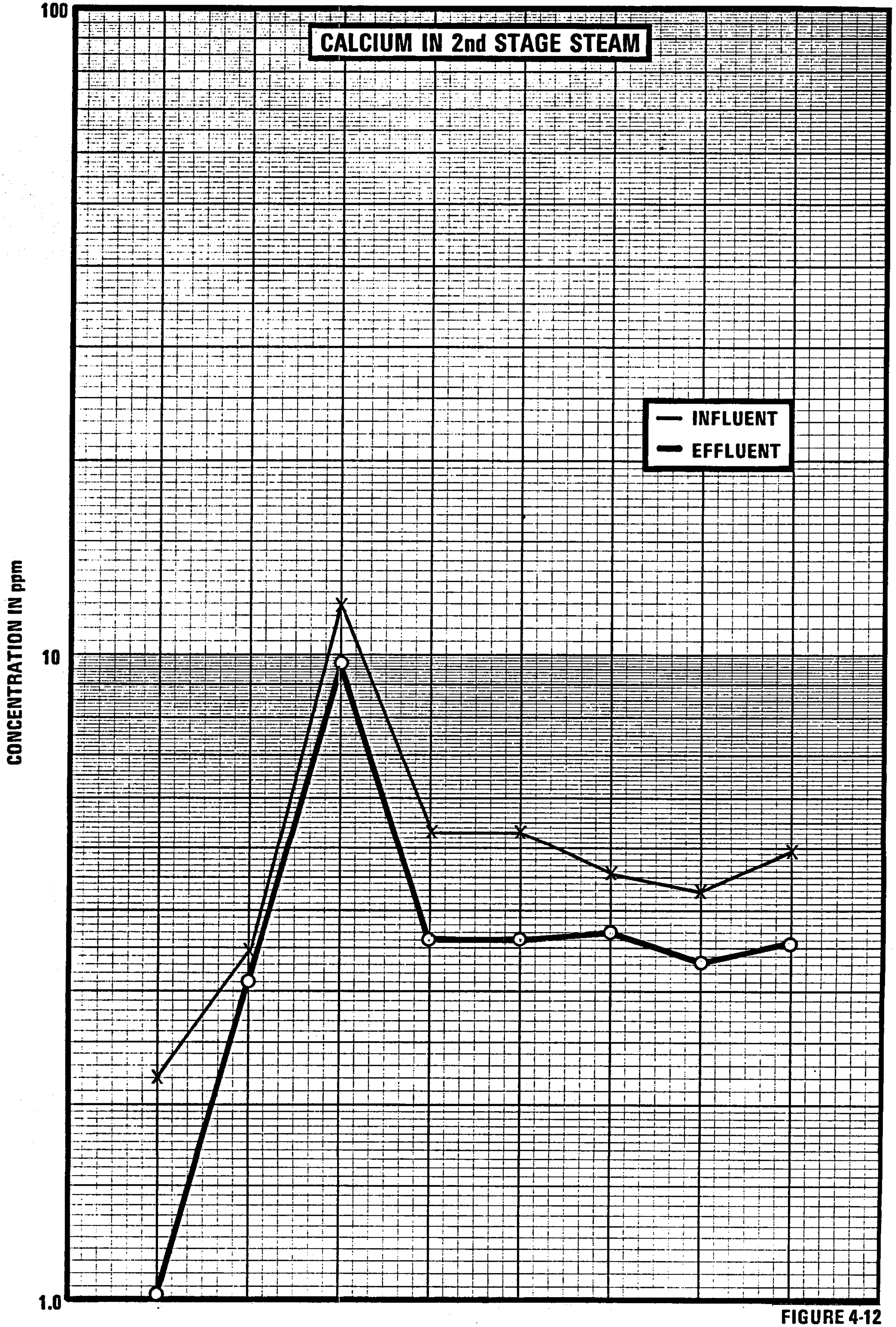

100
CALCIUM IN 2nd STAGE STEAM
INFLUENT
EFFLUENT
CONCENTRATION IN ppm
10
1.0

FIGURE 4-12

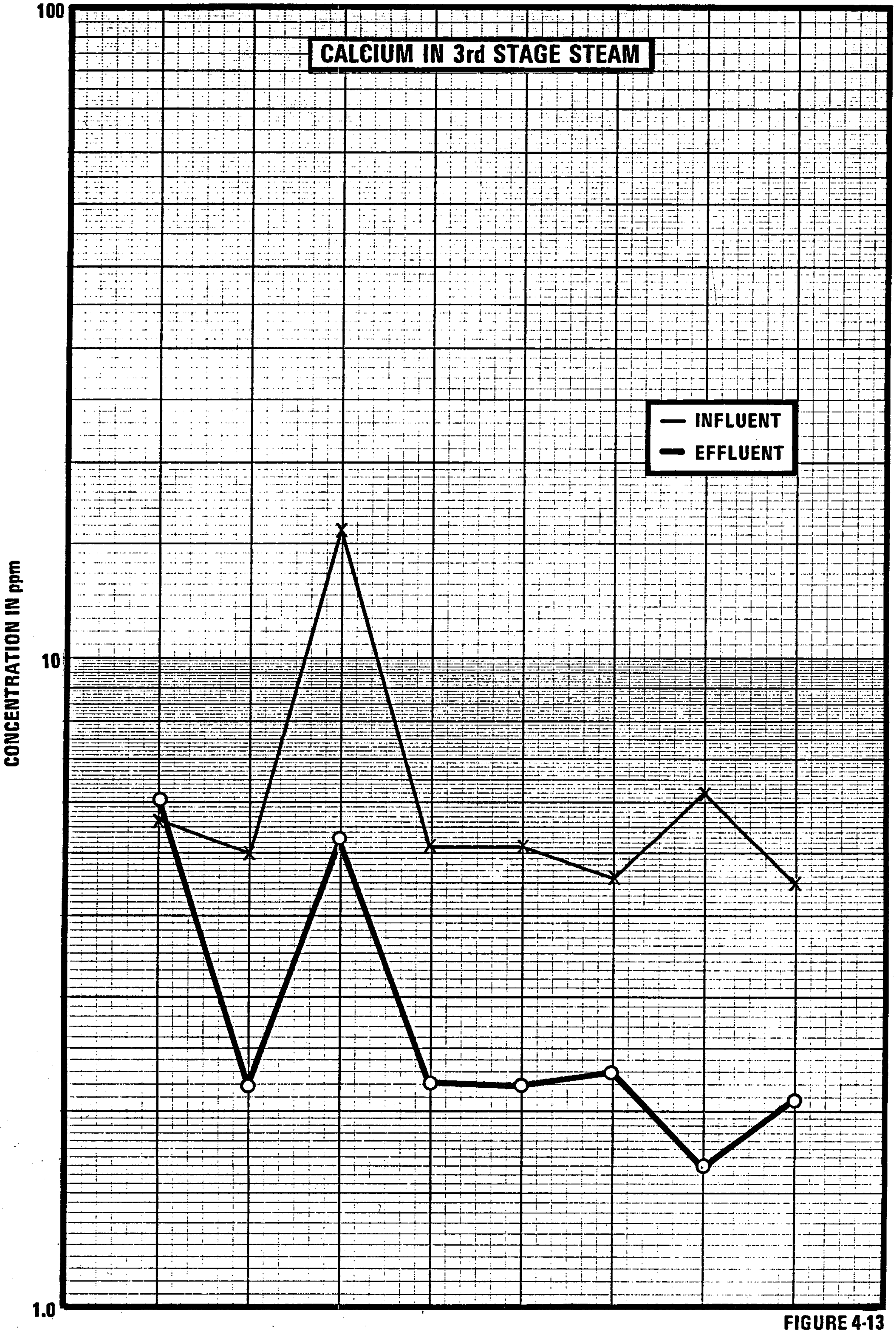
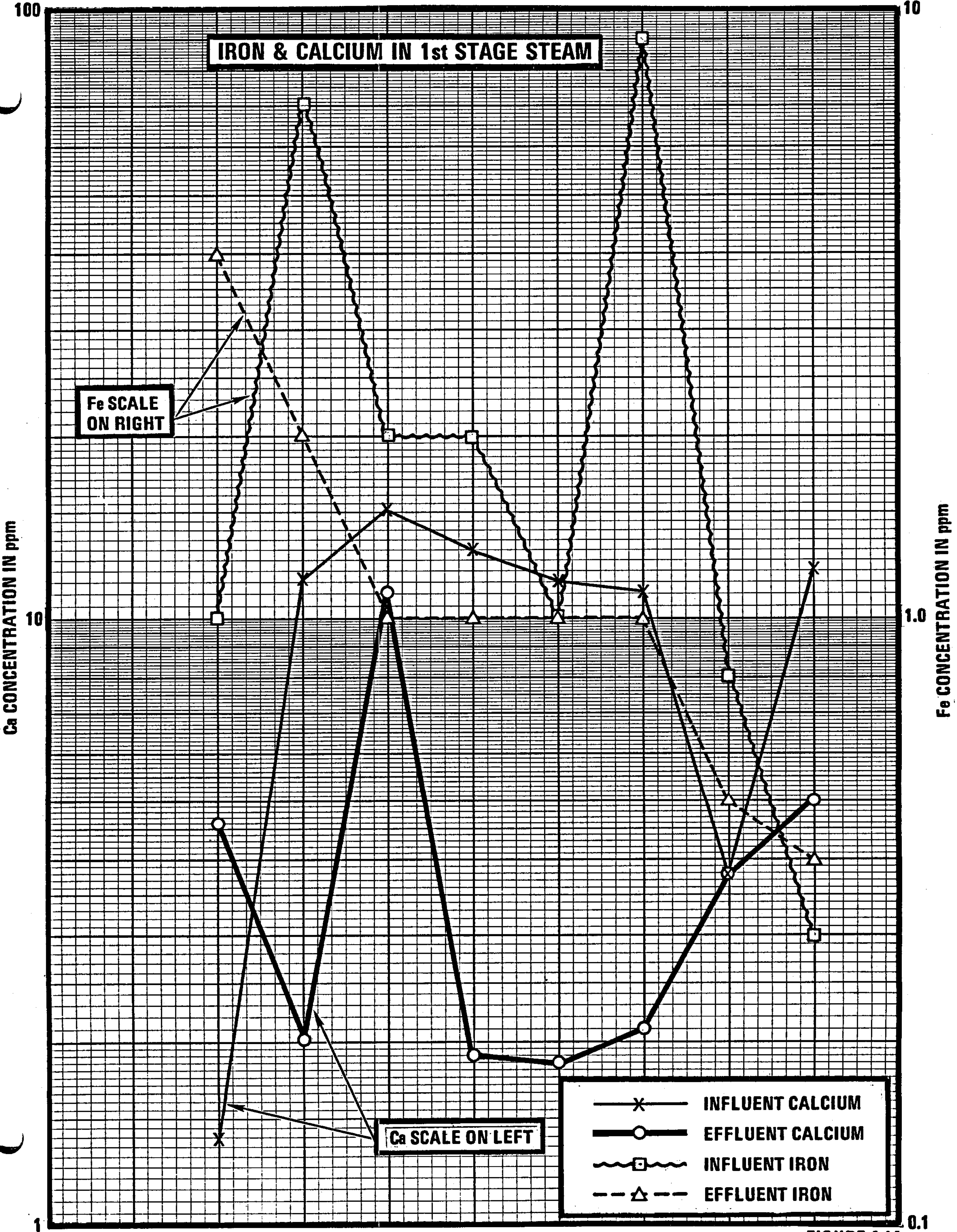

CALCIUM IN 3rd STAGE STEAM
INFLUENT
EFFLUENT
CONCENTRATION IN ppm
100
10
1.0

FIGURE 4-13



IRON & CALCIUM IN 1st STAGE STEAM
100
10
1
10
1.0
0.1
Ca CONCENTRATION IN ppm
Fe CONCENTRATION IN ppm
Fe SCALE ON RIGHT
Ca SCALE ON LEFT
INFLUENT CALCIUM
EFFLUENT CALCIUM
INFLUENT IRON
EFFLUENT IRON

FIGURE 4-14

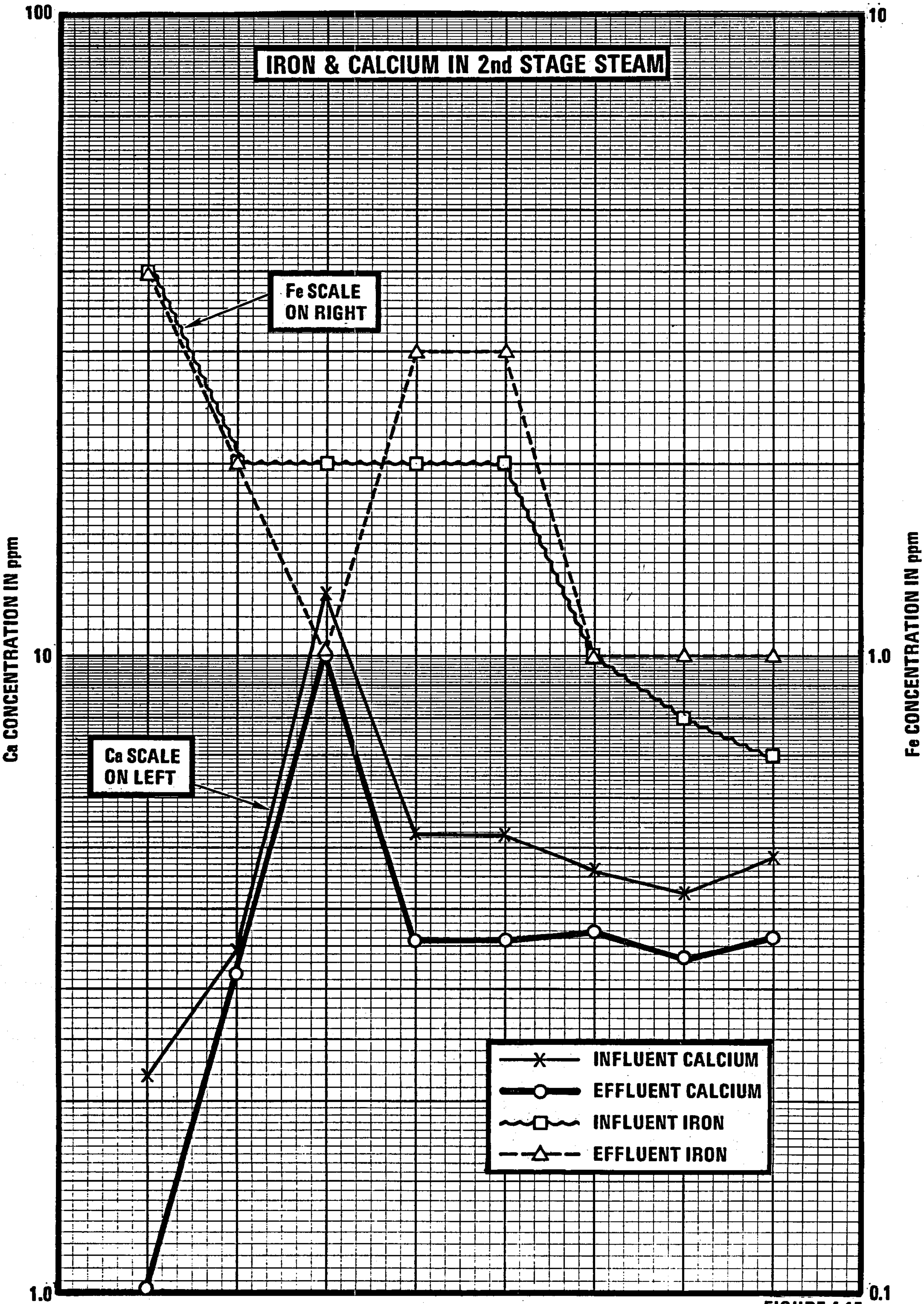

IRON & CALCIUM IN 2nd STAGE STEAM
100
10
1.0
10
1.0
0.1
Ca CONCENTRATION IN ppm
Fe CONCENTRATION IN ppm
Fe SCALE ON RIGHT
Ca SCALE ON LEFT
INFLUENT CALCIUM
EFFLUENT CALCIUM
INFLUENT IRON
EFFLUENT IRON

FIGURE 4-15

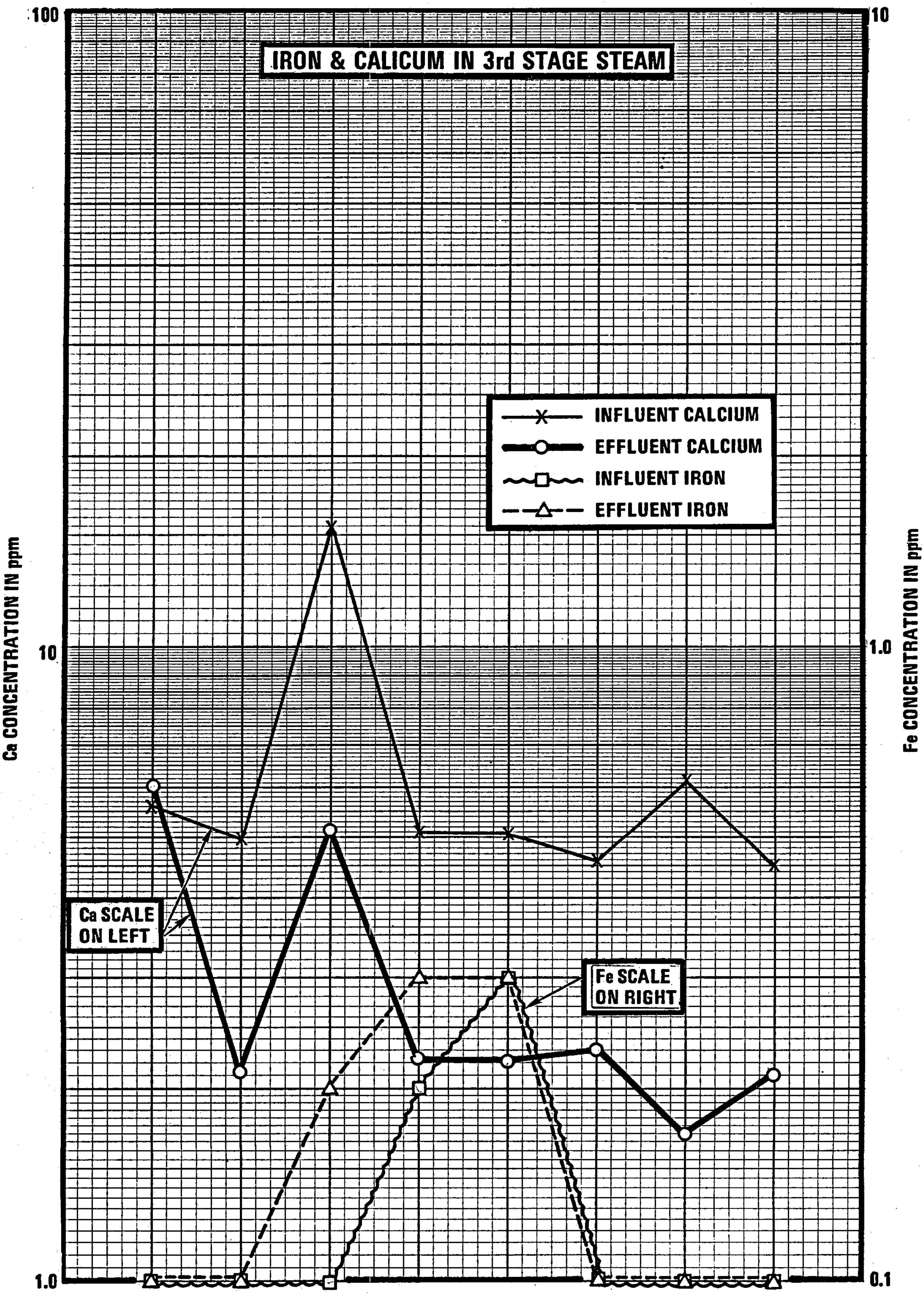

IRON & CALICUM IN 3rd STAGE STEAM
100
10
1.0
10
1.0
0.1
Ca CONCENTRATION IN ppm
Fe CONCENTRATION IN ppm
INFLUENT CALCIUM
EFFLUENT CALCIUM
INFLUENT IRON
EFFLUENT IRON
Ca SCALE ON LEFT
Fe SCALE ON RIGHT

FIGURE 4-16

The metallic ions can be conveniently categorized by concentration. First, those which form the major composition of the brine, sodium, calcium and potassium. In a second group are those present at 1/100 to 1/20 the value of the first group. Here are lithium, strontium, barium, iron, magnesium, manganese, and zinc. Nonmetallic elements silcon and boron also fit into this group. In a third group are copper, lead, and aluminum which are present in trace amounts.

Both the Total Dissolved Solids (TDS) and electrical conductivity (mho) increase as the brine passes through the plant due to water lost by flashing. The initial (well head) concentration (TDS) was 212,000 ppm. Conductivity was 310,000 u mho. By the time the brine reaches the fourth stage the concentration rises to about 270,000 ppm with a corresponding conductivity of 410,000 u mho. These values are tabulated in Tables 4-1 to 4-5. The pH values of the brine are, as might be expected, quite stable averaging from 5.2 in the well head increasing to 6.0 in the 1st stage. As with the steam, these changes in brine pH are ascribed to changes in dissolved gas concentrations.

Values of the specific ions are also tabulated in these tables. Concentration of the specific ions follow the changes in TDS and generally increase through the plant.

MAGMAMAX WELLHEAD BRINE

Sample port closed early in running of plant.

Date of Sample:	2-2
	ppm
Fe	139
Cu	1.2
Zn	---
Mn	---
Pb	35
Ba	---
Mg	220
Si	166
B	620
Ca	21500
Na	49200
K	9500
Li	---
NH_4	345
Sr	---
Al	1
Cl	118000
TS	212000
EH	105
pH	5.16
Cond.	310000
CO_3	8

Table 4-1

1st STAGE BRINE

Date of Sample:	2-28	3-6	3-13
	ppm	ppm	ppm
Fe	185	130	210
Cu	1	0	1
Zn	---	62	30
Mn	---	---	295
Pb	39	4	3
Al	1	2	1
Ba	---	70	70
Mg	240	---	45
Si	118	---	---
B	---	375	420
Ca	23500	18300	19800
Na	50000	50300	50800
K	10200	9950	9800
Li	---	---	240
NH_4	342	335	280
Cl	137200	151400	141000
CO_3	8	---	---
TS	240000	237000	233000
EH	-8	-6	-50
pH	6.08	6.04	6.32
Cond	375000	368000	350000
SO_4	---	---	30
Sr	---	400	250

Table 4-2

2nd STAGE BRINE

Date of Sample:	2-28	3-6	3-13	3-20	3-27
	ppm	ppm	ppm	ppm	ppm
Fe	195	150	200	275	375
Cu	0.5	0	2	1	0
Zn	---	90	100	450	590
Mn	---	---	370	315	720
Pb	35	7	50	30	5
Al	1	2	2	2	1
Ba	---	110	110	55	65
Mg	280	---	---	120	120
Si	160	175	240	150	---
B	---	350	430	315	360
Ca	25500	18000	25000	26500	24800
Na	50500	50600	51300	53000	51800
K	10800	10600	12400	23000	7400
Li	---	---	305	235	400
NH_4	426	405	475	340	310
Cl	141900	156000	156500	161500	149000
CO_3	---	720	---	---	22
Sr	---	460	240	295	305
TS	252000	251000	253000	260000	248000
EH	-8	-5	-10	+5	-29
pH	5.90	5.93	5.80	5.85	5.92
SO_4	---	---	35	35	---
Cond	380000	360000	385000	395000	405000

Table 4-3

3rd STAGE BRINE

Date of Sample:	2-28	3-6	3-13	
	ppm	ppm	ppm	
Fe	210	170	210	
Cu	0.5	0	2	
Zn	---	85	160	
Mn	---	---	390	
Pb	40	10	65	
Al	2	3	2	
Ba	---	150	70	
Mg	250	55	55	
Si	140	225	175	Sample port closed.
B	---	440	420	
Ca	27000	19500	25600	
Na	51000	50800	51300	
K	11000	11000	22000	
Li	---	---	310	
NH_4	440	410	530	
Cl	200	---	---	
CO_3	200	---	---	
Sr	---	---	260	
TS	267000	266000	267000	
EH	6	3	-2	
pH	5.64	5.75	5.66	
SO_4	---	---	35	
Cond	400000	395000	400000	

Table 4-4

4th STAGE BRINE

Date of Sample:	2-28	3-6	3-13	3-20	3-27
	ppm	ppm	ppm	ppm	ppm
Fe	220	150	225	320	345
Cu	0.6	0	2	0	0
Zn	---	---	155	380	252
Mn	---	---	400	345	790
Pb	60	8	70	55	70
Al	3	3	2	2	1
Ba	---	150	265	180	95
Mg	250	---	---	130	---
Si	125	---	155	150	---
B	---	470	445	405	405
Ca	27000	19500	27200	27000	27300
Na	51000	50900	57500	62000	53600
K	11200	11000	14100	6000	8900
Li	---	---	325	280	430
NH_4	470	495	525	470	460
Cl	147000	167000	167000	164000	162000
CO_3	49	85	---	46	36
Sr	---	---	280	305	335
TS	271000	266000	277000	274000	271000
EH	21	26	25	22	32
pH	5.36	5.45	5.34	5.72	5.12
Cond	410000	410000	390000	420000	435000
SO_4	---	---	30	30	45

Table 4-5

4.3 Scale

During the operation of the GLEF, scale is deposited on all surfaces wetted by the geothermal brine. The major constituents of this scale are silicon, iron, and sodium. Silicon, mostly as $Si0_2$, is the predominent specie. Except for some of the heavy metals (probably as sulfides) the scale is almost entirely an amorphous silica-iron matrix with some sodium, probably as evaporated salts, inclusions.

As noted in previous reports, the silica content of the scale increases as the brine temperature is lowered. (See Tables 4-6 to 4-11). Scale on vessels surface not immersed in the geothermal brine is predominately iron, probably from corrosion of the mild steel vessels.

SCALE ANALYSIS
SEPARATOR DRAINS

% of scale (dried)

January 1978

Location Element (Ion)	1A	1B	2nd Stage	3rd Stage	4th Stage
Fe	26.43	11.84	15.81	4.88	.50
Cu	.39	.15	.50	.72	.53
Zn	.21	.07	.13	.17	.13
Mn	1.69	1.08	2.29	.62	.16
Pb	1.3	13.0	---	---	---
Ba	0.11	.03	.20	1.44	2.60
Mg	1.44	.53	.18	.11	.04
Si	16.80	11.33	24.10	35.47	33.80
* SiO_2	35.94	24.24	51.56	75.88	72.31
Ca	3.13	.73	.77	.95	2.80
Na	1.60	4.00	3.80	4.60	10.67
K	.31	.43	.62	.49	1.05
Li	-0-	.01	.01	.01	.03
Sr	.07	.06	.06	.06	.17
CO_3	.01	Trace	.01	-0-	.06

* Silicon as SiO_2

Table 4-6

SCALE ANALYSIS
SEPARATOR BELOW WATER LINE

% of scale (dried)

January 1978

Location Element (Ion)	1B	3rd Stage	4th Stage
Fe	15.73	8.18	.59
Cu	.71	.76	.16
Zn	1.24	.11	.09
Mn	1.17	.56	.14
Pb	13.0	2.06	.30
Al	.02	.04	.02
Ba	-0-	-0-	.02
Mg	1.30	.08	.08
Si	1.42	35.88	34.00
* SiO_2	3.04	76.76	72.74
Ca	1.26	1.01	2.60
Na	8.40	4.80	14.10
K	.37	.23	.85
Li	.02	.01	.04
Sr	.11	.70	.11
CO_3	-0-	-0-	.01

* Silicon as SiO_2

Table 4-7

SCALE ANALYSIS
SEPARATOR CEILING

% of scale (dried)

January 1978

Location Element (Ion)	1B Silver Color	1B Black Color	3rd Stage	4th Stage
Fe	54.20	47.64	51.80	33.73
Cu	.07	.11	.08	.26
Zn	.04	1.44	.03	.28
Mn	.89	.94	1.16	1.01
Pb	.67	1.85	.28	1.47
Al	.02	.02	.01	.01
Ba	-0-	-0-	-0-	.02
Mg	.04	.12	.04	.05
Si	1.60	3.40	2.43	8.60
* SiO_2	3.42	7.27	5.20	18.40
Ca	1.05	.85	.62	1.03
Na	.27	2.40	2.30	2.80
K	.01	.02	.04	.28
Li	.01	.01	.01	.01
Sr	.10	.12	.07	.15
CO_3	.01	.01	-0-	Trace

* Silicon as SiO_2

Table 4-8

SCALE ANALYSIS
TOP OF SCRUBBER

% of scale (dried)

January 1978

Location Element (Ion)	1st Stage	3rd Stage	4th Stage
Fe	64.00	59.00	44.80
Cu	.04	.04	.05
Zn	.98	.19	.23
Mn	.44	.68	2.02
Pb	.26	.10	.30
Al	.02	.02	.01
Ba	.00	-0-	-0-
Mg	.02	.02	.02
Si	.28	.87	.37
* SiO_2	.60	1.86	.79
Ca	.06	.21	9.47
Na	.21	.14	.14
K	-0-	-0-	-0-
Li	-0-	-0-	-0-
Sr	.06	.04	.07
CO_3	-0-	Trace	.20

* Silicon as SiO_2

Table 4-9

SCALE ANALYSIS
INJECTION LINE

January 1978

Location Element (Ion)	P-2	Elbow above 1A Separator	Daniels Spool	Flange Before Rd.	Flange After Road
Fe	1.07	1.11	.43	.31	.25
Cu	.85	.63	.60	.21	.20
Zn	.16	.16	.08	.05	.05
Mn	.10	.45	.27	.09	.08
Pb	---	---	---	---	---
Al	---	---	---	---	---
Ba	3.85	4.27	4.77	4.13	1.99
Mg	.04	.04	.03	.02	.02
Si	42.73	38.13	34.60	26.60	31.33
* SiO_2	91.42	81.58	74.02	56.91	67.03
Ca	.66	4.60	3.00	3.20	3.40
Na	2.87	3.67	6.47	9.20	8.73
K	.32	.37	.50	.82	.74
Li	.01	.01	.01	.03	.03
Sr	.15	.18	.15	.15	.13
CO_3	.03	.02	.02	Trace	-0-

* Silicon as SiO_2

Table 4-10

SCALE ANALYSIS
INJECTION LINE

January 1978

Location Element (Ion)	1st Exp. Loop Elbow	1st Exp. Loop Outlet	4th Exp. Elbow Inlet	4th Exp. Loop Elbow	4th Exp. Loop Outlet Pipe
Fe	.25	.26	.37	.19	.16
Cu	.20	.22	.15	.16	.15
Zn	.05	.05	.04	.04	.04
Mn	.08	.07	.07	.07	.06
Pb	---	---	---	---	---
Al	---	---	---	---	---
Ba	2.04	2.11	2.21	2.27	1.82
Mg	.02	.02	.02	.02	.02
Si	29.00	32.13	28.87	30.73	30.87
* SiO_2	62.04	68.74	61.76	65.74	66.04
Ca	3.40	3.40	4.00	4.20	3.80
Na	8.53	6.67	7.60	5.93	5.47
K	.67	.57	.60	.55	.53
Li	.03	.02	.03	.02	.02
Sr	.14	.11	.13	.14	.15
CO_3	Trace	Trace	Trace	.00	Trace

* Silicon as SiO_2

Table 4-11

5.0 MAINTENANCE

5.1 Scale Removal

5.1.1 Pigging

Flexible foam pigs, manufactured by Girard Polly-Pig have been used to remove soft silica scale from the injection line on a daily basis. The pigs were being damaged intermittently earlier in the quarter.

Late in January the plant was shut down to investigate the reason for the pigs being damaged. A spool piece in the injection line was removed and two pigs were launched. One came out in good shape and the other one came out multilated. The Southwest Chemical Company filled the injection line from the fourth stage separator level control valve up to the first 90° elbow with acid and let it soak for about 24 hours. Four foam pigs were then run through as before. Although they were not torn up, they came out damaged. A power brush pig (a heavier constructed pig with more wire brush area) was run down the line but was caught in the line near the second 90° elbow. After an attempt to remove it with two swabs, (soft blank pigs) a regular wire brush pig was launched and successfully drove the power brush pig out.

After this, pigging has continued once daily with pigs exiting in good shape.

5.2 Component Optimization

5.2.1 Pinch Valves

During the February 6 shutdown, the Red and Galigher pinch valves were inspected. These valves were tried as control valves on the 3rd stage brine drain. Scale was found sticking to the rubber but the rubber linings were still intact. However, on February 27, the Red Valve lining ruptured. At this time the Red Valve and Galigher Valves were removed and replaced with the original Kymar Valve.

5.2.2 Brine System Valves - Packing

In the past, John Crane style 187-1 packing has been used in the brine system valves. This packing consists of braided asbestos packing with wire inserted with graphite. When the packing comes in contract with the brine, it turns very hard. When the packing gland starts to leak, the packing will not compress and the valve stems become pitted and scored.

During the January shutdown, SDG&E purchased 2 lbs. of Chesterton teflon packing style 201 for evaluation. This is enough to pack two valves. The results of the use of this packing will be discussed in the next quarterly report.

6.0 SPECIAL PROBLEMS

6.1 Injection Pump

On February 19, the injection pump (P-2) started losing pressure and the 4th stage separator was not pumping down. The plant and injection pump (P-2) were shut down. An attempt to turn the pump P-2 by hand was made to no avail. Purge water and acid to P-2 bearing was increased for 5 minutes and freed the pump, but a starting of the pump produced a zero discharge. The pump P-2 was shut down, removed and delivered to the SDG&E Machine Shop for repair. Because of the extended overhaul time, the Machine Shop built a new shaft, impellers, bearings and casing bowl. Basically, a new pump was manufactured with the exception of the head and suction bell. This will allow extended operation of the facility.

On February 22, the new pump was tested satisfactorily and the plant was returned to service.

Over the weekend of March 25 and 26, the injection pump P-2 began losing discharge pressure and flow. Under one-well operating conditions, the flow was in excess of 500 gpm with a pump discharge pressure of 550 psig. By noon on March 26, the discharge pressure and flow were 365 psig and 472 gpm, respectively.

A hydroblast nozzle was installed at the injection pump's suction bell to test its effectiveness in removing scale in this area. Between 2:00 p.m. and 4:00 p.m. on March 26, water at pressures of 5,000-10,000 psi was supplied to the hydroblast nozzles in an attempt to improve the pump's performance. Very little improvement was noted after the cleaning operation was completed.

By 8:00 a.m. on Monday, March 27, the pump discharge was 435 gpm at 160 psig. Since a shutdown appeared imminent, and doing so would interfere with clarifier tests being conducted by Magma Power, methods of cleaning the pump in place without shutting down the plant were discussed. GLEF operating personnel suggested flushing the pump with irrigation water by introducing it into the 3 inch vent line at the top of the can to remove any scale formed between the pump and the can. It was also suggested that water be forced through the hydroblast nozzles at the pump suction bell to create additional turbulence to help break up any loosened debris.

At 1:00 p.m. hydroblasting began, followed 10 minutes later by the flow of irrigation water through the vent line. At 1:20 p.m., more cooling water was introduced through the 3 inch line used to dump cooling pond water into the reservoir. This line enters the 4th stage brine discharge line about 5 feet upstream of the pump suction inlet. The combination of the three cooling water flows plus the brine flow reached a maximum of about 1000 gpm during the operation.

The flow through the vent line was secured first at 1:40 p.m. followed by the cooling pond water flow at 2:00 p.m. The hydroblast flow was shut off last at 2:10 p.m. After adjusting the brine flow control valve back to normal conditions (510 gpm), the pump discharge pressure was 555 psig. The in-place cleaning of the pump was apparently successful.

It is felt that while all three flows undoubtedly contributed to cleaning the pump, the more important were the low pressure flows into the vent line and the 4th stage outlet line - particularly the latter. Channel 27 on the datalogger records the brine temperature at the elbow immediately before the inlet to the pump can. During the past several weeks, this thermocouple has been reading low by about 40°F, obviously due to excessive scaling of the thermowell. After the cleaning, the reading was noted to be apparently accurate again. The cooling pond water addition apparently removed much of the scale from the thermowell and probably from the rest of the pump suction line as well.

Two factors appear to have contributed to the pump cleaning - the increased flow velocity and turbulence caused by doubling the flow rate, in conjunction with the thermal shock of mixing cool water with relatively hot brine. To test which factor dominates, it was suggested that the brine flowrate be temporarily increased (if possible) the next time the pump discharge pressure begins to decrease. If this technique fails, it was suggested that cooling pond water next be added to only the 4th stage brine discharge line as addition of cool water at this point produced the most tangible results during the cleaning operation.

Because of the success of this cleaning operation, the installation of additional low-pressure cooling water flush lines are planned. They will be located in areas where large amounts of soft scale accumulate (i.e. the 4th stage drain outlet). The effectiveness of these flushing ports will be evaluated during the next several months.

6.2 Condensers

In the past, fouling on the cooling water side of the condensers (tube side) has caused excessive pressure drops that have bent the water channel baffle plates. To prevent a recurrence, pressure gauges were installed at the condenser inlet and outlet, and the pressure drop limited to 20 psi. Since mid-January, the pressure drop has been increased steadily. This limitation required a reduction in the cooling water flow rate to 8700 gpm from a normal flow rate of 16,000 gpm.

The plant was shutdown and the condenser covers were removed. Large amounts of debris and scale were noted and removed from the tubesheets. After the covers were reinstalled, the plant was restarted on February 4. The cooling water flow rate was initially higher, but quickly deteriorated to 1200 gpm with a 20 psi pressure drop. The plant was then shutdown on February 6 to clean the entire condenser and study methods of preventing scale build-up in the future.

A scale sample from the tubes was analyzed and consisted primarily of iron oxide. Because of the large volume of scale present, it is speculated that some of the iron oxide is precipitating from the cooling water (which has a high iron content) rather than forming from the corrosion of the tubes themselves. This precipitation, in combination with corrosion, virtually closed off many of the condenser tubes.

Mechanical cleaning was necessary to remove the large quantities of scale that had accumulated in, and in some cases completely plugged the tubes. Southwest Chemical Co. was retained to hydroblast the condensers.

Their crew arrived and began setting up at 8:00 a.m. on Tuesday, February 7, and began cleaning by noon. The job was originally estimated to take four to five days.

However, mechanical difficultites with Southwest's equipment stretched this time considerably. The cleaning operation was finally complted on Tuesday, February 14.

During the hydroblasting operation, three inch flanges were welded to each condenser inlet and outlet pipe to allow acid cleaning of the condensers. Southwest crews began circulating inhibited hydrochloric acid in the condensers for about fifteen hours. The condensers were then flushed with cooling water for several minutes. The condensers were again isolated (without draining) and corrosion inhibitors (100 ppm of a chromate-based inhibitor and 150 ppm of NALCO 7350) were circulated for 24 hours. After this pre-treatment with corrosion inhibitors, the cooling water system was started up. The cleaning operation tremendously improved the flow through the condensers. A flow of 16,000 gpm resulted in a pressure drop of only 12 psi.

The plugging of the condensers was probably caused by a combination of factors. These factors are discussed below.

1) Excessive Iron Concentration in Cooling Water

Since precipitation of iron oxide apparently caused at least some of the scale build-up, it was speculated that excessive concentrations of iron were present in the cooling water. The pond water at the time of shutdown contained 1.53 ppm iron, well in excess of iron's solubility in water. The iron has accumulated over time because the cooling water has been diluted by blowing the pond down only infrequently. In addition, an accidental lowering of the pH in August, 1977 may also have contributed to the iron content of the pond.

2) Additional Chlorination of Cooling Water

The steam condensate used as makeup for the pond contains a relatively large concentration of ammonia. Once in the pond, this ammonia promotes the growth of algae. To combat this growth, chlorine was added to the circulation pump suction pit. The amount of chlorine required to counteract the effect of the ammonia on algae growth may have been sufficient to a) directly attack the steel of the condenser tubes, increasing their corrosion rate, and/or b) react with the zinc compounds of the corrosion inhibitor, thereby reducing its effectiveness and increasing the corrosion rate.

3) Excessive Debris in Condensers

When the condenser covers were removed the first time, a large amount of debris was noted, consisting of wood chips and other organic matter. This debris may have contributed to the build-up in the condenser tubes by providing convenient nuclei to which the iron oxide could adhere. The screens originally installed in the circulating sump suction pit were removed soon after the plant began operating when they became clogged with debris and collapsed due to the pressure difference across them. At that time, debris in the condensers was not felt to be a problem.

6.3 Solutions

The following is a list of proposed solutions to the problem that resulted from discussion with SDG&E, Bechtel and Holt personnel.

1. Since chlorine probably caused at least a portion of the condenser corrosion, replace it with another biocide. If an environmentally acceptable substitute can be found, the corrosion of the condenser due to chlorine addition would be eliminated.
2. Continue to use chlorine as an algae inhibitor, except change it's point of addition from the pump suction to the pond itself. Part of the corrosion may have been caused by pumping the chlorine directly through the condensers and then through the spray nozzles before the chlorine became diluted in the pond. Also, a large portion of the chlorine may have been lost to the atmosphere in the water spray before it even entered the pond.
3. Remove the ammonia from the steam condensate used as cooling water make-up. This would reduce the attractiveness of the pond to algae and would reduce the amount of biocide required. The best method of removing the ammonia appears to be air-stripping. The condensate would have to be pH adjusted and sprayed into the pond in a fine spray.

4. Re-install the screens in the pump suction pit. This would remove large particles of debris which contribute to condenser plugging. To avoid another screen collapse, a regular screen cleaning program would have to be implemented.
5. Change corrosion inhibitors to a chromate-based type, which would be more effective than the zinc based NALCO product currently used. This method would have to be checked for environmental acceptability.
6. Drain the spray pond and refill it with irrigation water to reduce the total amount of solids and some of the least desireable elements in the pond, such as iron.
7. Maintain a continuous blowdown flow from the pond. This would prevent the build-up of iron and other undesireable elements in the cooling water.
8. Retube the heat exchangers with a corrosion resistant material such as titanium. This would be costly but would minimize or eliminate corrosion of the condenser tubes.
9. Monitor the pressure differential across, and flow rate through, the exchangers when the plant begins operating. When the flow resistance begins to increase, acid-clean the condensers to remove corrosion products and scale.

10. Establish a target cooling water chemical composition and attempt to operate the pond as near as possible to the target.

11. Install a tube-cleaning device that functions while the plant is operating. This type of device has been used on heat exchangers to eliminate fouling and maintain design heat transfer coefficients.

These proposed solutions will be evaluated in the next reporting period and the best selected for implementation.

The problem of condenser corrosion and plugging appears to be very complex. The use of geothermal condensate as makeup water for the cooling system may be the cause of many of the problems seen to date. An effective cooling water treatment program, designed to handle the condensate, may be the best short term solution to this problem. A long term solution that can be utilized in a commercial power plant (such as constructing the condensers of appropriate materials) must eventually be addressed.

7.0 OTHER ACTIVITIES

7.1 Feasibility Study

A feasibility study was recommended by the GLEF Program Evaluation Committee (refer to the January, 1978 Quarterly Report - Feasibility Study). The purpose of the Feasibility Study is to re-evaluate the future test program to maximize the usefulness of these future activities.

A draft report on Phase I of the Feasibility Study was completed in March, 1978. The report initially reviewed GLEF data and the results of related activities to date. A cycle selection was accomplished along with a prioritization of the remaining risks associated with the selected cycle. Finally, GLEF activities were recommended to minimize the remaining risks.

The major conclusions of the draft report are as follows:

1. A dual flash cycle, using unmodified brine, redundant brine systems and no limit on injection temperature yields a 50 MWe power plant design net with a minimum cost per kwh and minimum risk. Other cycle alternatives, limited to present state-of-the-art hardware, were more costly and generally with more of a risk.
2. Principal remaining risks are related to brine handling in the plant and reservoir. Scale, corrosion and injection questions were identified as critical.

Major recommendations for future GLEF activities are:

1. The modification of the plant brine system to simulate the selected dual flash conversion cycle.
2. The installation of a brine effluent treatment facility.
3. To conduct tests primarily to define scale, corrosion, and injection control and parameters.

These basic recommendations have been accepted by SDG&E, Imperial Magma and the Department of Energy. The preliminary engineering, and solicitation of bids have begun. Initial plant modifications will be incorporated in the next shutdown, scheduled for mid-April.

7.2 H_2S Abatement

The FMC Corporation has proposed testing a hydrogen sulfide control system using hydrogen peroxide and sodium hydroxide. This system has been used in the petroleum and kraft paper industry for hydrogen sulfide control. It has also been used at the geysers to remove hydrogen sulfide from geothermal steam.

In the FMC process hydrogen sulfide is oxidized in the presence of sodium hydroxide to form sodium sulfate. Sodium sulfate could form scale in our vertical vent stack, but is very soluable in water. Water vapor condensing and running down the stack may be sufficient to remove any deposition for long term testing. Some type of water wash may be required, but for the short test proposed no scaling problem is expected.

7.3 Plant Engineer

SDG&E has established the position of Plant Engineer at the facility. The Plant Engineer will be responsible for the implementation of the test program and the design of minor plant modifications. The Plant Engineer should significantly improve the usefulness of GLEF activities in general, especially the test program.

8.0 SUMMARY

The plant operated for a total of 1284 hours during this period, bringing total plant operation from start-up to 7163 hours. The average plant capacity factor for this period was 58%.

Magma installed a pilot reactor clarifier to test the possibility of accelerating the precipitation of suspended solids in the effluent brine. The clarifier effluent averaged 40 ppm suspended solids as compared to 100 ppm from the settling tanks.

Scrubber performance tests were again run this quarter. The results showed that there are uncertainties in the measurements of scrubber efficiency at all wash water flowrates. One reason for this appear to be that surging in the brine flow causes oscillations in the amount of steam contamination entering the scrubber.

Ph, electrical conductivity, total dissolved solids, chloride, sodium, calcium, found in the brine, steam and scale are generally consistent with previous measurements.

The injection pump began losing discharge pressure on March 25. The pump was hydroblasted at the pump suction bell and flushed with irrigation water through the vent line and the 3 inch pipe line that is used to dump cooling water into the reservoir. This in-place cleaning successfully restored the pump discharge pressure.

Large amounts of debris and scale restricted flow in the cooling water condensers. Mechanical and chemical cleaning was necessary to remove this material which consists primarily of iron oxide. Because of the large volume of scale present, it is speculated that some of the iron oxide is precipating from the cooling water rather than forming from corrosion of the tubes themselves. The cooling water also contains large amounts of ammonia which promotes algae. To counteract the growth of algae, chlorine is added to the pump suction which may increase the rate of corrosion in the tubes. Proposed solutions are being evaluated to solve this problem.

The plant will be modified in the next reporting period to a parallel two stage flash cycle as recommended by the 1977 feasibility study. A Plant Engineer was added to the staff at the GLEF for this implementation of the test program and to improve the GLEF activities.

APPENDIX A

SAN. DIEGO GAS & ELECTRIC COMPANY
INTERNAL CORRESPONDENCE
FORM 115-6143L

FROM F.J. DeLamarter DATE 2-8-78

TO W.O. Jacobson / N.C. Hodgdon FILE NUMBER

SUBJECT SUMMARY OF SHUTDOWN PERIOD FROM JANUARY 5 TO JANUARY 21, 1978

Before shutdown for cleaning the plant was in operation for 1067hrs since last cleaning. The plant was shutdown at 2210, Jan. 5 and continued to run P-2 to flush pump and reinjection line with cooling water until 2400.

The routine procedures for normal shutdown were followed except for the following exceptions:

1. The separator level columns were not rodded out but the top and bottom lines from column to separators were rodded out.
2. The spool piece at the Daniel's orifice was removed for inspection of reinjection line instead of the 1st test coupon.
3. The reinjection line from P-2 discharge to the elbow above 1A separator was hydroblasted. The rest of the reinjection line was not cleaned except for under the road. There was about ¼" of scale in the reinjection line.
4. P-10 condensate pump was not removed on inspection except for checking for free rotation.
5. Sump pump was not removed or inspected except for checking for free rotation.
6. PCV 300 was not removed. Valve was still free.
7. PCV 301 was replaced with a spare valve that had been cleaned previously.
8. LCV 714 was removed, inspected, cleaned and reassembled, but not installed. The Galagher and Red valves were installed in it's place. New bladders were installed in each valve. The Red valve is made of the same material (EPR) but with a different laminate. The Galagher had Buna N. and it was replaced with a Neopreame.

9. LCV 719 was not removed due to free movement and not much use.

10. The condensers were not opened for inspection.

11. The vacuum pump was not open for inspection.

A unique situation on this shutdown, was that Daedalean Associates, Inc., from Maryland, cleaned the drain line from the 3rd stage separator to the 4th separator using the cavitation method.

Other jobs that were completed during this shutdown include the following:

1. Relocated P-3 discahrge valve up near the condensers.
2. Modified the 1st, 2nd, and 3rd stage scrubber drains to go through individual lines into a manifold into the 4th stage separator.
3. Installed a level controller and Kymar valve on the vacuum pump seal water tank to P-10 suction line.
4. Installed a flow orifice on the vacuum pump discharge line to the stack.
5. Installed a weld o let, flange, and gate valve on the 1st stage steam line for a turbine flow meter.
6. Installed a separate 3" line to flow condensate from pumps out to the spray pond through 2 spray nozzles.
7. Installed 20 weld o lets on Woolsey supply line and placed rods into the lines.
8. Made modifications to the Vortex breakers on each separator.
9. A nozzle was placed at bottom of P-2 with a purge line hooked up in order to attempt to keep the suction of pump cleaned.

APPENDIX B

A COST-EFFECTIVE TREATMENT SYSTEM
FOR THE
STABILIZATION OF
SPENT GEOTHERMAL BRINES

Prepared By:

Robert H. Van Note, Technical Consultant
Envirotech Corporation, San Mateo, CA

John L. Featherstone, Mgr. Technical Services
Imperial Magma Company, El Centro, CA

Bernard S. Pawlowski, Sales Engineer
Envirotech Corporation, Garden Grove, CA

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ABSTRACT

In view of the rising costs for fossil fuel and the realization that such fuels are exhaustible, increasing attention has been focused on the earth's heat as a source of energy. It has been estimated that geothermal resources in the United States alone could produce 140,000 megawatts of power over a life expectancy of 30 years. This is the equivalent of 140 nuclear generating units. However, there are unsolved problems associated with utilizing geothermal brines to produce energy. Recent test work conducted at the Imperial Valley, California, provides a solution to one of these major problems.

A treatment system has been developed in which spent geothermal brines from a flash tank heat extraction plant are stabilized to permit reinjection of the treated brine while maintaining the integrity of the wells over an extended period. This treatment system is both cost-effective and environmentally sound. It incorporates the following unit process operations:

- Reconstituting the minerals which were dissolved from the geothermal strata formations in a Reactor-Clarifier by solids contact precipitation reactions.
- Polishing of the clarifier effluent in a gravity dual media filter.
- Thickening and storage of sludge produced in the Reactor-Clarifier.
- Dewatering of the sludge to an optimum cake moisture suitable for handling and land disposal.

INTRODUCTION

A project was initiated in July, 1975 at the Salton Sea Known Geothermal Resource Area in Imperial Valley, California, to demonstrate the viability of converting the underlying geothermal brines to energy. The project includes four wells drilled by Imperial Magma; two of which, Magmamax #1 and Woolsey #1, are production wells. The other two wells, Magmamax #2 and Magmamax #3, are injection wells. At present, brine from Magmamax #1 well feeds a four stage flash heat extraction plant at the San Diego Gas & Electric/Department of Energy Geothermal Loop Experimental Facility. Spent brine from the flash system is transported via a pipeline approximately 5000 ft. to Magmamax #3 well and is injected back into the formation.

Chemical analyses of the spent brine at the point of injection is presented in Table 1. This brine is supersatured with respect to heavy metals and silica. Precipitation of these components in the injection well along with plugging of the strata with discrete suspended solids in the brine has adversely affected the integrity of the injection well. The viability of the complete project is in jeopardy unless cost-effective methods can be devised to stabilize the spent brine prior to injection.

In December 1977, personnel of Imperial Magma and Envirotech Corporation met to discuss methods of treating the spent brine to produce a non-scaling liquid suitable for well injection. At that time, it was conceived that auto-precipitation of minerals in the spent brine could be achieved in a solids contact clarifier, producing an effluent of stable saturated levels of silica and heavy metals.

Accordingly, a pilot plant Reactor-Clarifier was furnished by Envirotech Corporation to Imperial Magma in February, 1978. The unit was installed adjacent to Magmamax #3 injection well and operated continuously 24 hours per day, 7 days per week from February 28, 1978 to April 12, 1978, constituting the first phase of test work.

TABLE 1 - CHEMICAL ANALYSIS OF SPENT GEOTHERMAL BRINE TREATED IN PILOT PLANT REACTOR - CLARIFIER

Constituent	Concentration - PPM
Sodium	53,276
Potassium	10,259
Calcium	22,414
Chloride	134,483
Iron	272
Manganese	685
Zinc	207
Lead	53
Copper	>1
Barium	129
Silicon as SiO_2	293
Magnesium	177
Total Dissolved Solids	228,448
pH	5.6
Temperature Range	180°F - 200°F 82°C - 93°C

REACTOR-CLARIFIER

The fundamental component of the spent geothermal brine treatment system described later is the Envirotech Reactor-Clarifier. The unit operates on the principle of solids-contact clarification whereby large volumes of sludge (10-15 times the volume of feed) are recirculated internally through a draft tube/impeller arrangement to a reaction well. Previously precipitated sludge recirculated in this manner comes in intimate contact with the feedstream in the reaction well, providing seed nuclei on which dissolved solids in the feedstream precipitate under controlled conditions of temperature, reaction time and solids concentration.

The resultant liquid/solid mixture flows from the reaction well into the clarification compartment where liquid and solids are separated by gravity. Treated liquid overflows into collection launders at the upper surface of the unit. Rake arms are used to move the settled sludge to a center thickening cone at the bottom of the tank where the thickened sludge is discharged by gravity or pumps.

The Envirotech pilot plant Reactor-Clarifier furnished on this project is 8'-0" diameter x 10'-6" sidewater depth. All external surfaces of the tank are insulated to minimize heat loss of the spent brine. Area of the clarification zone is 37.7 sq. ft.

The results of this test work have led to a contract for a 55'-0" diameter Envirotech Reactor-Clarifier having 2375 total surface area which will have the capability to treat the total flow of spent brine from a 10 MW two-stage flash heat extraction demonstration plant.

FIGURE 1 – SUMMARY OF PILOT PLANT RESULTS

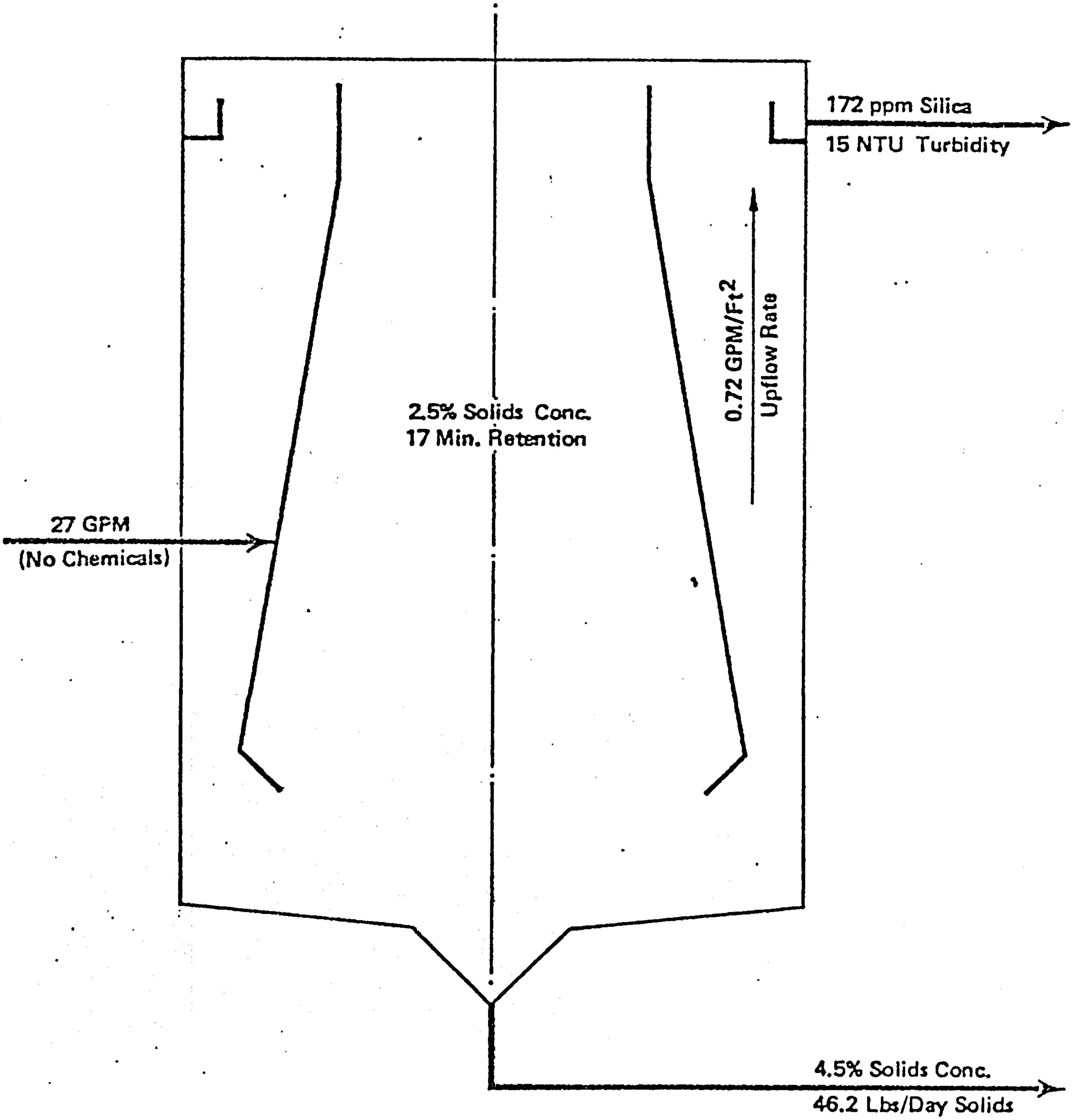
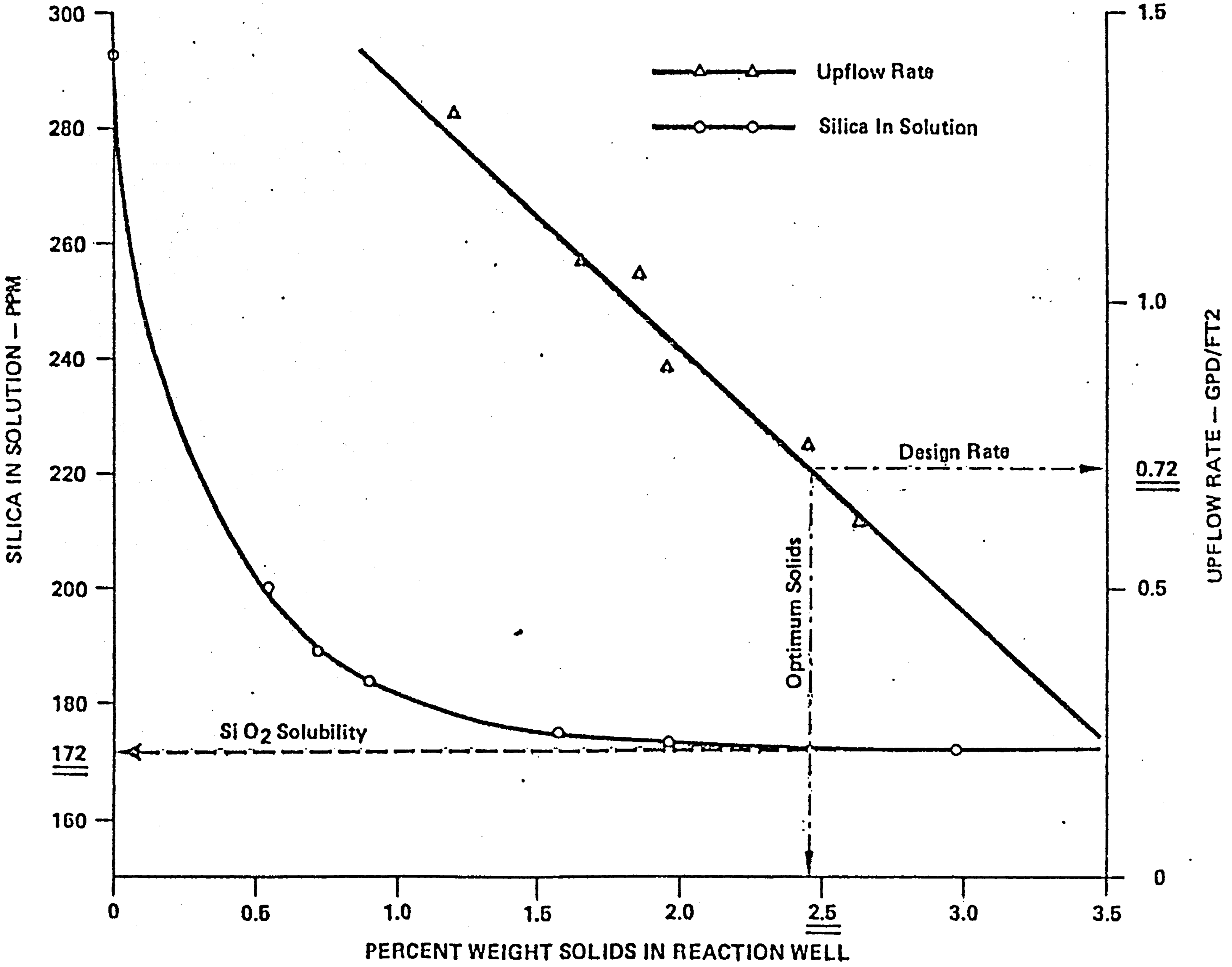


FIGURE 2 – REMOVAL OF SILICA BY SOLIDS CONTACT CLARIFICATION PROCESSING



DESIGN EXPERIMENT

A design experiment was formulated at the outset of the first stage test program to derive useful results for the development of a viable and cost-effective system for the treatment of spent geothermal brine and for the handling and disposal of sludges produced in the brine treatment processing.

The objectives of the design experiment were to:

- Determine that the original concept of auto-precipitation of minerals in the spent brine was feasible.
- Determine design criteria of the Reactor-Clarifier for sizing on a commercial scale, including:
  - Upflow rate
  - Reaction well retention time
  - Solids concentration in reaction well
- Measure the effluent quality with respect to silica and turbidity concentrations from the Reactor-Clarifier under varying conditions of design criteria noted above.
- Determine the thickening and dewatering characteristics of sludge produced and determine the most viable type of dewatering equipment to use.
- Correlate all data collected to:
  - Provide optimum design criteria for the production of stable saturated levels of silica in the Reactor-Clarifier effluent.

- Establish criteria for polishing of the Reactor-Clarifier effluent.
- Determine sludge handling and disposal requirements.
- Estimate order of magnitude costs for spent brine treatment and sludge handling and disposal for a 55 MW geothermal energy plant.

PILOT PLANT TEST RESULTS

Summary

Average test data, based upon optimum design criteria, are presented in Figure 1. Summation of these data for optimum design criteria follows:

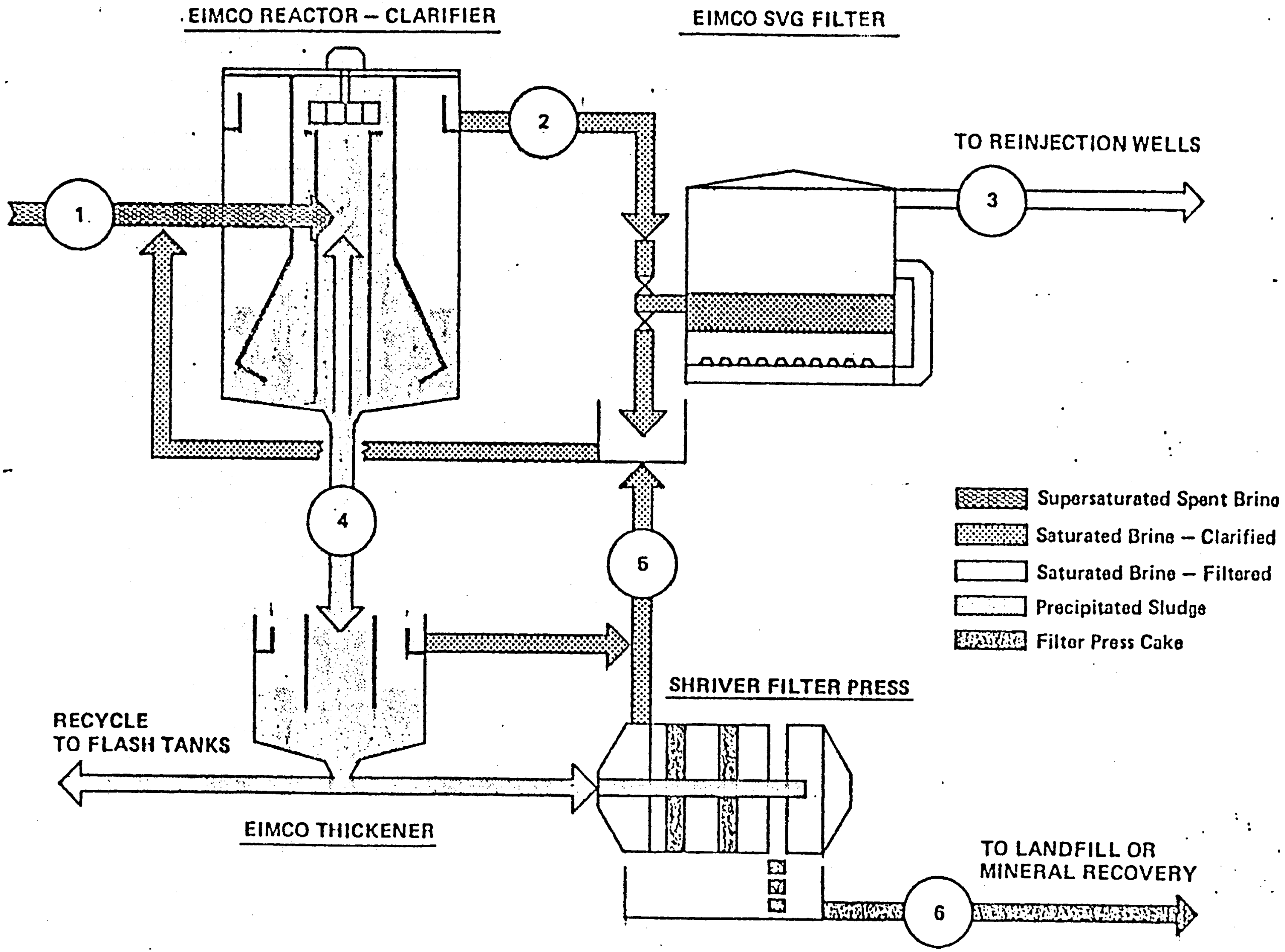
- No chemicals are required in the treatment of spent geothermal brines.
- Upflow Reactor-Clarifier Rate = 0.72 GPM/Ft^2
- Solids Concentration in Reaction Well = 2.5%
- Reaction Time in Reaction Well = 17 minutes
- Effluent Quality at Design Criteria
  - Silica - 172 ppm
  - Turbidity - 15 NTU (44 ppm s.s.)
- Sludge Produced:
  - 1.7 lbs/day per GPM
- Sludge Characteristics:
  - From Reactor-Clarifiers - 4.5% solids
  - From Thickener - 10% solids
  - From Filter Press - 65% solids

Details of these summary results follow.

Brine Treatment

Test results that the quantity of silica remaining in solution in the Reactor-Clarifier effluent is a function of the insoluble solids concentration held in the reaction well. As shown in Figure 2, a stable solubility level of 172 ppm SiO_2 is achieved when the solids concentration in

FIGURE 3 – STABILIZATION OF SPENT GEOTHERMAL BRINES



the reaction well approaches 2.5% solids by weight. Further increases above the design concentration range do not markedly improve silica removal.

The capacity of a Reactor-Clarifier is dependent upon the settling rates of precipitated solids in the unit. It cannot be operated at an upflow rate greater than the settling rate of the precipitated solids; otherwise, clarification would not occur. In accordance with the Kynch theory, solids in hindered settling exhibit settling velocities inversely proportional to the solids concentration in the zone through which they settle. This is verified in Figure 2. Upflow rates as high as 1.33 GPM/ft^2 can be maintained in the Reactor-Clarifier when relatively low solids concentrations in the reaction well are held at approximately 1.2% solids by weight. As these concentrations are increased, upflow rates must be reduced accordingly; down for example, to a measured low of 0.62 GPM/ft^2 at a solids concentration of 2.63%.

In achieving a cost-effective process, there exists a compromise between the continuous production of stable saturated effluent from the Reactor-Clarifier and the maximum permissible upflow rate in the unit. Test data shows that an optimum solids concentration of 2.5% by weight can be maintained in the reaction well while permitting a maximum design upflow rate of 0.72 GPM/ft^2 to produce the desired stable saturated effluent of 172 ppm SiO_2.

Sludge Handling and Disposal

Insoluble solids produced in the Reactor-Clarifier by auto-precipitation (no addition of foreign chemicals or send material) were collected from the Reactor-Clarifier sludge blowdown and analyzed. A proximate chemical analysis of these insoluble solids is presented in Table 2. Silicon is the major constituent of the total insoluble solids, representing approximately 90% by weight as silica and possible other complex silicate forms. Heavy metals including iron, strontium, manganese, lead and copper appear to precipitate as sulfide and oxide minerals and perhaps, other complex forms.

Quantities of solids produced in the Reactor-Clarifier as measured by sludge blowdown under optimum conditions is 1.7 lbs/day per GPM brine fed to the unit.

An Envirotech-Shriver Filter Press was used near the end of the first phase test work to determine the dewatering characteristics of the sludge on this device. These tests showed that the sludge could be dewatered easily, producing a filter press cake of 65% solids by weight. Earlier test work indicated that centrifuges and vacuum drum filters could produce a cake no greater than 50% solids by weight. At the same time, the filtrate from the filter press was essentially free of suspended solids while the centrate from the centrifuge contained as much as 1% solids by weight. The filtrate/centrate must be returned to the Reactor-Clarifier. High solids concentrations in this recirculated stream could adversely affect the performance of the Reactor-Clarifier.

TABLE 2 - PROXIMATE CHEMICAL ANALYSIS OF INSOLUBLE SOLIDS IN REACTOR - CLARIFIER SLUDGE

Constituent	Weight % Solids	ppm
Silicon as Si	(42.82)	
As SiO_2	91.75	
Silver		97
Copper	0.13	
Nickel		23
Manganese	0.31	
Magnesium	0.08	
Lead	0.18	
Iron	0.85	
Cobalt		4
Chromium		18
Arsenic		85
Calcium	7.92	
Aluminum	0.02	
Barium		6
Boron	0.02	
Cadmium		2
Rubidium	0.01	
Selinium		73
Zinc	0.06	
Strontium	0.63	
Cesium		33
Sulfur	1.06	
Total Constituents Weight	103.05%	

Notes:

1. All concentrations greater than 100 ppm are expressed to nearest 0.01% solids by weight.

2. Total constituent weights are greater than 100%, possibly due to some silicon being in complex forms other than SiO_2.

Test work to date has indicated that disposal of filter press cake at 65% solids in lined ponds is the most cost-effective and environmentally sound alternative. It is possible that metals could be recovered from the filter press cake which offers some savings in the overall costs of a spent brine treatment operation.

SPENT GEOTHERMAL BRINE TREATMENT SYSTEM

Sufficient data has been collected from the phase one test program to prove the adequacy of design of a spent geothermal brine treatment system for any given capacity. Test work, however, is continuing. Further planned test work comprises the following:

- Phase 2 - Pilot plant operations including a Reactor-Clarifier, Gravity Sand/Anthracite Filer, Sludge Thickener and Filter Press on the same pilot scale as reported above (to be started approximately July 15, 1978).
- Phase 3 - Demonstration plant operation including a Reactor-Clarifier, Gravity Sand/Anthracite Filter, Sludge, Thickener and Filter Press to treat spent geothermal brine from a 10 MW heat extraction plant facility. (To be started approximately February 15, 1979)

The brine treatment systems used for both Phase 2 and Phase 3 test programs will be as shown in the simulated flowsheet in Figure 3. Commercial operation of a spent geothermal brine treatment system is expected at this time to embody an identical flowsheet.

ORDER OF MAGNITUDE COSTS

Based upon test results presented above and upon cost information derived from projects of similar nature and size, order of magnitude costs for spent brine treatment and sludge handling and disposal for a 55 MW geothermal generating station are presented in Table 3.

As shown, it is estimated that the unit cost on a present worth basis for brine treatment is 11¢/1000 gallon brine treated (0.9 mills/KWH). Estimates for sludge handling and disposal is 8¢/1000 gallon brine treated (0.7 mills/KWH) for a total treatment cost of 19¢/1000 gallon brine treated (1.6 mills/KWH). Chemical costs are not included in this analysis in that it is felt that chemical addition in any form is not required to produce the required effluent qualities. 2¢ - 5¢/1000 gallon brine treated should be added to these estimates if chemicals if chemicals were to be used.

TABLE 3 - ORDER OF MAGNITUDE COSTS FOR SPENT BRINE TREATMENT AND SLUDGE HANDLING AND DISPOSAL FOR A 55 MW GEOTHERMAL GENERATING STATION

PROCESS	PRESENT WORTH ($1,000,000)	UNIT COSTS ¢/1000 Gal.	 Mills/KWH
Brine Treatment			
Reaction, Clarification & Gravity Filtration	15.2	11	0.9
Sludge Handling & Disposal			
Thickening & Dewatering	8.4	6	0.5
Disposal	3.1	2	0.2
Sub-Total	11.5	8	0.7
TOTAL	26.7	19	1.6

Includes Installed Capital Costs and O&M Costs

Life of Plant = 30 years

On Line Plant Factor = 90%

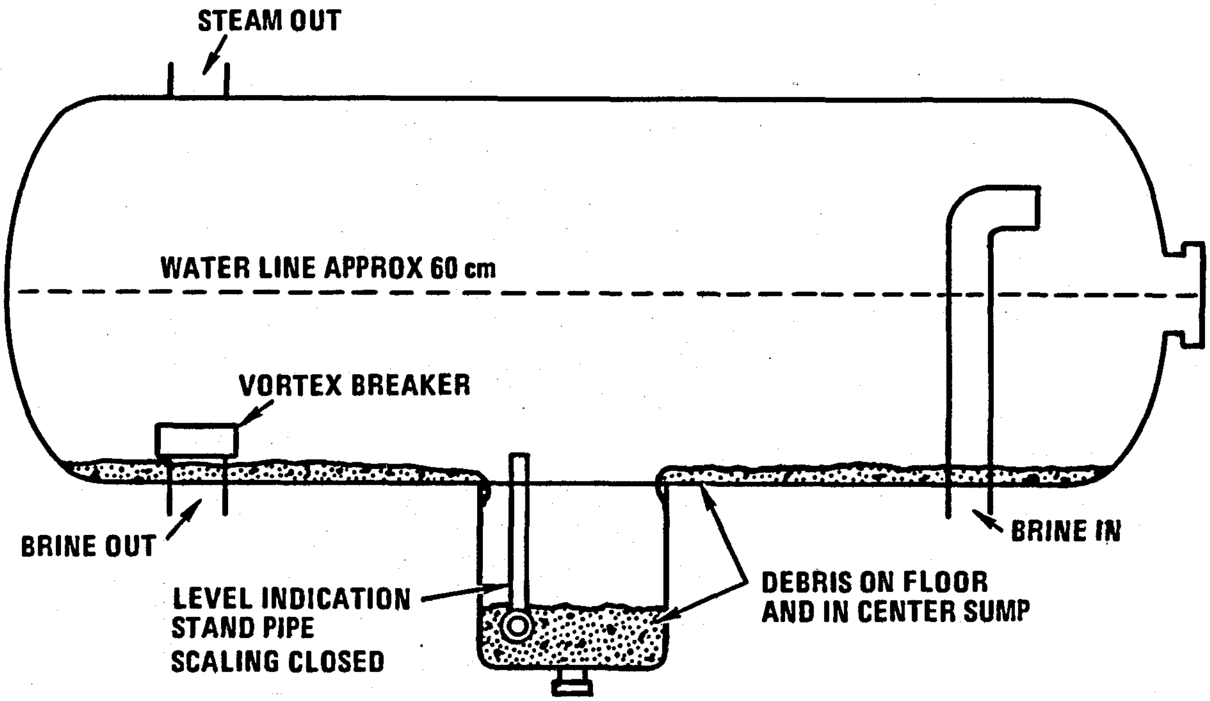
APPENDIX C

1A FLASH VESSEL

This vessel is supplied by Woolsey Well. It had a run time this operating period of 158 hours. Upon entering this vessel, I became aware of a strong smell of ammonia.

The scale below the water line was a thin rust brown scale (that had to be scraped off the wall) building at the vessel center to approximately 2mm thick. The debris from the floor was a thick brownish grey slurry 8 to 10 cm deep extending the full length of the vessel.

The level indication stand pipe in the center sump was scaling closed. The remaining opening was lcm in diameter. The water line was approximately lm. The Vortex breaker was coated with a layer of scale approximately lmm thick.



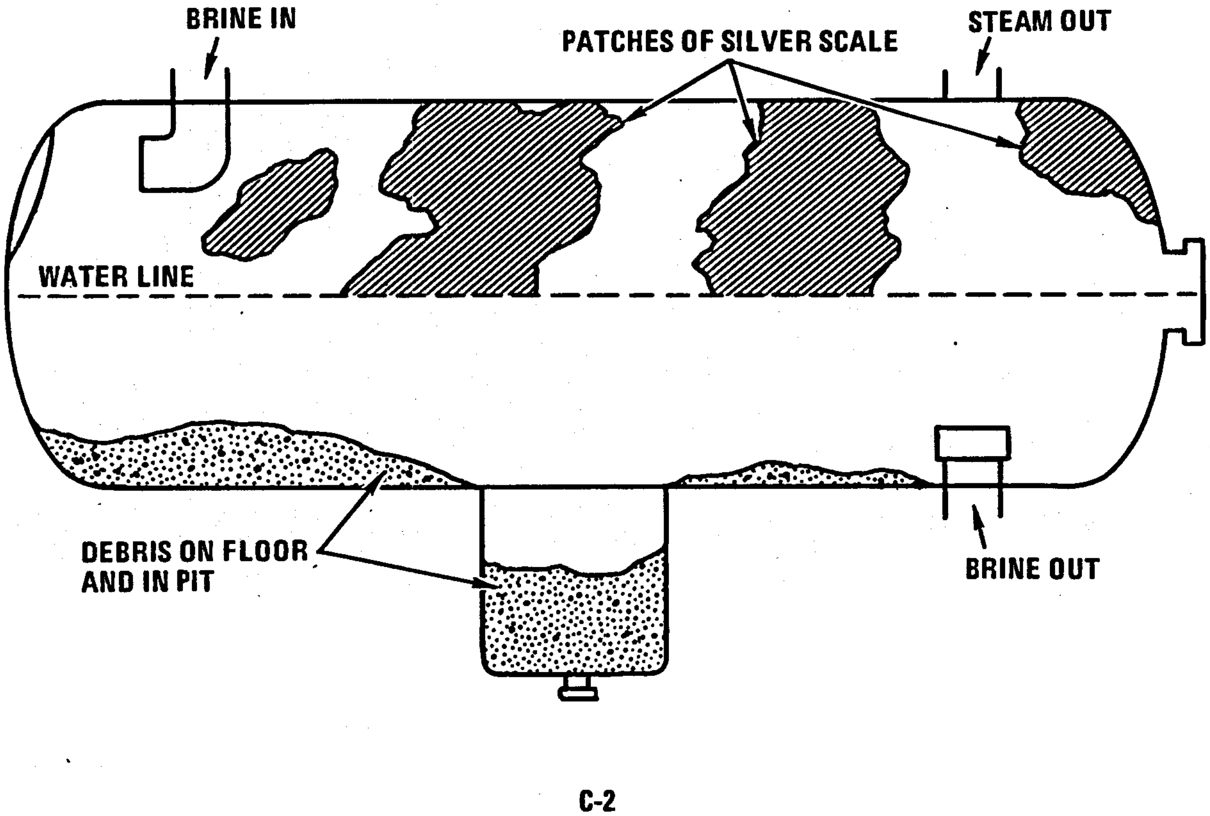
1B FLASH VESSEL

Supply well for tnis vessel was Magmamax #1. Run time on this vessel was 1067 hours.

Walls and ceiling were covered with large patches of silver scale. The scale was less than 1mm thick and samples were taken off both areas where silver existed and areas where it did not.

The water line was at about 75cm. Scale below the wate line was about 3 - 5 mm thick. The debris on the vessel floor was a metalic grey in color. It was a mushy sludge covered with a hard surface about 2cm thick. The debris covered an area approx 2.5 meters long extending from the inlet end. The pile was about 40cm deep.

The center sump was approx ½ full of scale. The level indication stand pipe was scaled closed to approx lcm opening. The outlet line below the Vortex was closed to 9.5cm by a hard black scale.



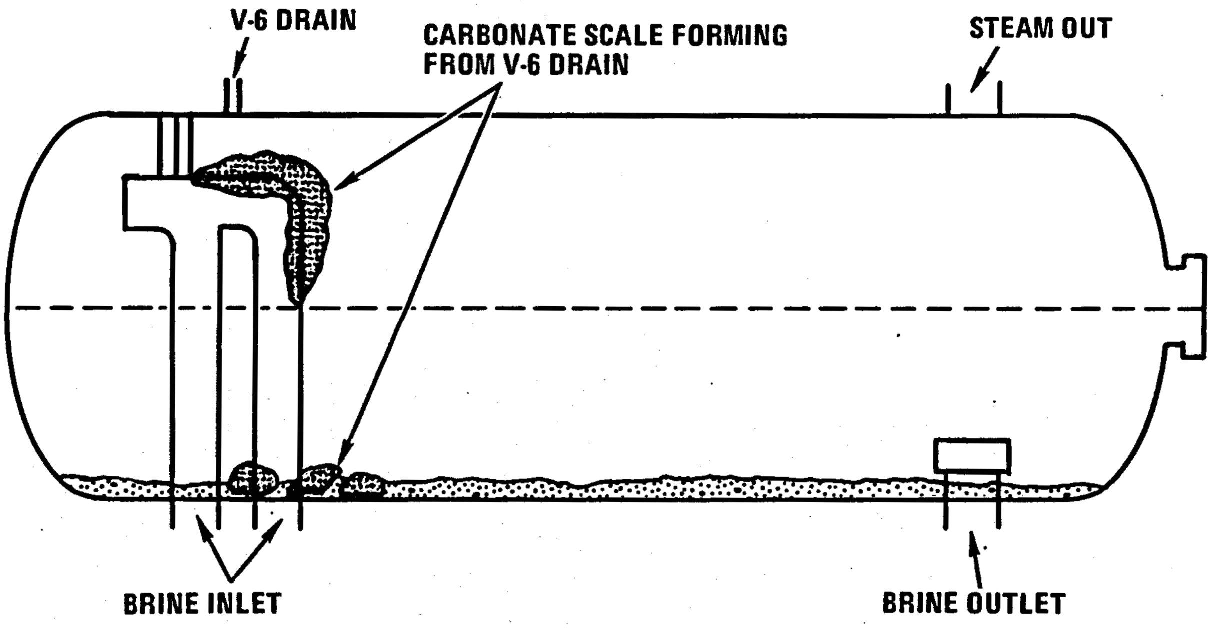
2nd STAGE FLASH VESSEL

Brine from both supply wells is combined here. The vessel is stainless steel clad. The scale on the ceiling was a fine red brown powder less than 1mm thick which had had to be scraped away.

The water line was approx .75m high. The scale below the water line varied in thickness from .1 to 1cm thick.

The inlet pipe which is located below the drain line from V-6 (vent gas separator) shows its continuous build up of carbonate scale. The scale forms in large lumps 15 - 20cm thick which ultimately falls away and builds again. The vessel wall in this area shows a decisive deterioration of the stainless cladding along the horizontal weld. The debris on the floor was about 15cm deep and extended the full length of the vessel.

The water level indication line was plugged to less than 1cm.



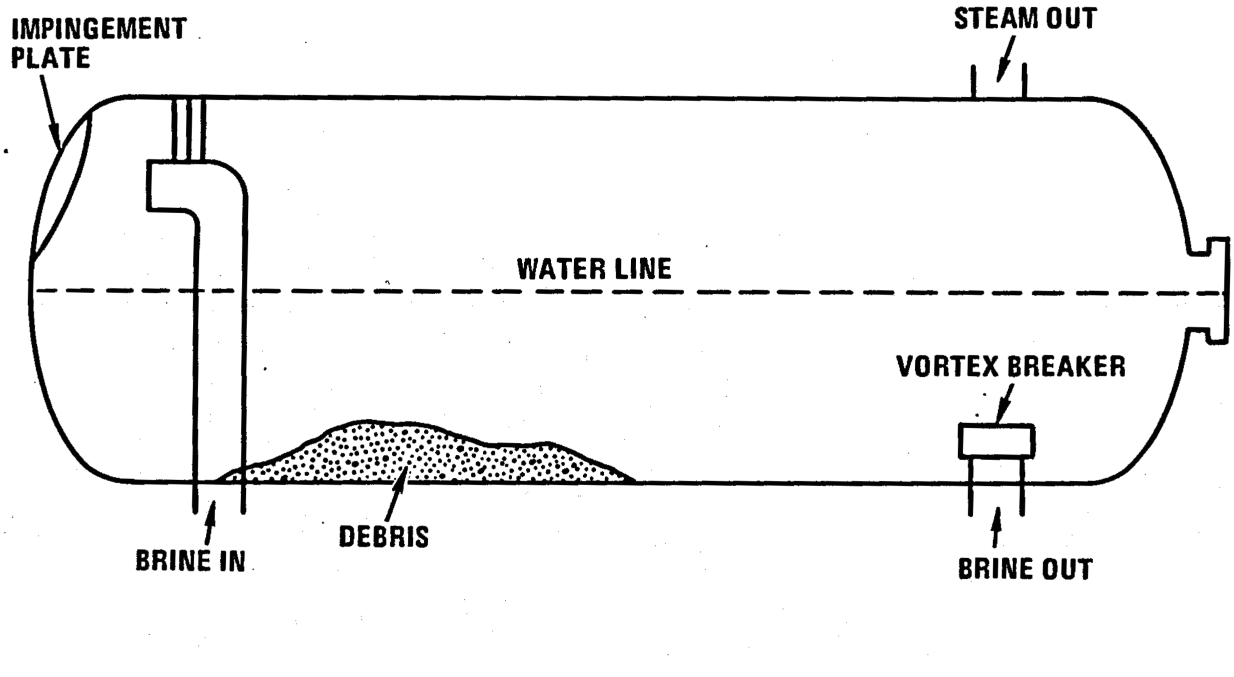
THIRD STAGE FLASH VESSEL

The ceiling was covered by a rusty metallic scale of 0.5 to 1mm thick. The scale was falling away leaving a heavy pitting of the vessel wall.

The water line appeared to be at about 70cm. The scale on the wall below the water line was very hard and brittle with a thickness of 1 - 5mm. The scale on the Vortex breaker appears to be the same as that on the vessel walls except in thickness where it reaches 1 cm.

The debris on the floor forms a pile approx 1 meter long and 20cm deep. The scale or debris itself appears to be based on debris from the ceiling - a metallic rust center with scale forming and building on both sides. The sizes vary up to 2cm thick with some pieces up to 15cm across.

The impingement plate was sparsely covered with a hard brown scale less than 1mm thick. This scale contained traces of green color possibly representing copper. The inlet nozzle has apparently the same type of scale with a thickness of approx 1cm.



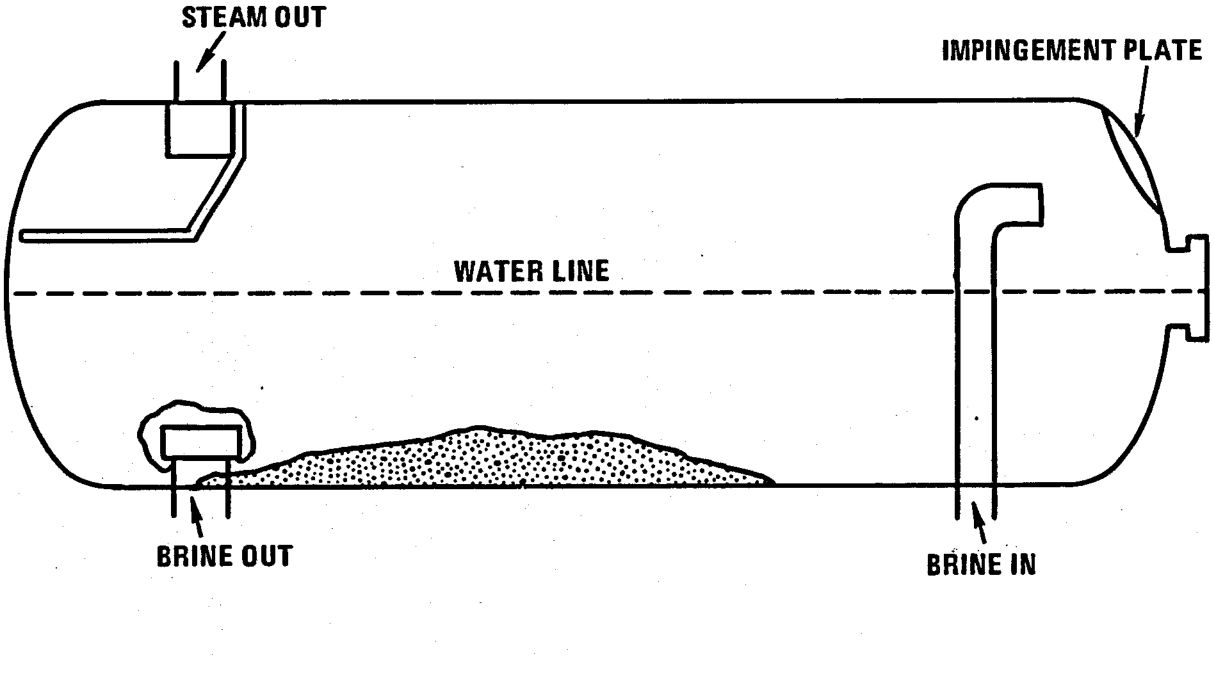
FOURTH STAGE FLASH VESSEL

The ceiling was covered with a metallic black scale which was forming blisters and falling away. This scale was 1 - 2mm thick. This type of scaling is resulting in a pitting of the vessel ceiling.

The water line was about .75 meters. Scale on the walls below the water line averaged about 5.5 cm thick and was a yellowish olive color, mushy in texture and was sliding away toward the vessel floor.

The baffle plates are rusting badly and were covered by slabs of rusting scale. The floor was covered by a pile of soft sludge 30cm deep and 3 meters long. The area under the impingement plate is covered by a hard black scale which is grey in color under the outer layer.

The inlet pipe was covered within by an extremely hard and brittle black scale which varied in thickness from 0.5 to 3cm thick. The Vortex breaker was covered with scale 2-3cm thick with a hard outer surface. The outlet line itself contained scale 3-5 cm thick.



FIRST STAGE STEAM SCRUBBER

The lower level shows a severe degree of rust damage and indications of heavy carry over of brine from the flash vessels.

The top of the vessel was very clean by comparison, indicating that the carry over does not seem to be passing through and that the scrubbing must be effective.

SECOND STAGE STEAM SCRUBBER

The second stage steam scrubber contained several cm of rusty scale on the lower level but was otherwise in excellent condition.

THIRD STAGE STEAM SCRUBBER

This contained a moderate amount of rust and was in very good condition.

FOURTH STAGE STEAM SCRUBBER

This stage contained large amounts of carbonate scale on the walls of the lower level up to 10cm thick. The upper level contained a black scale less than 1mm thick and falling away.

CONCLUSIONS

The cecession of acid treatment has resulted in a return to the sludge type scale in the Fourth Stage Flash Vessel. Although this is an easily removed scale, it builds rapidly and results in closure of the outlet line. This scale had resulted in shutdown of the plant on 12-19-77 to clean the 4th stage outlet to allow continued operation.

The rusting continues and pitting is spreading to other vessels. Pitting had first raised its ugly head in the third stage but has now spread to the fourth stage. The stainless cladding of the second stage exists now in name only, its surface has been reduced to a rusty stainless with areas as along the horizontal weld, where there is actually evidence of probabal pitting.

The rusting and pitting appears to be a problem, above the water line in the vessels and some attention will have to be paid to it in the future.