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FOSSIL ENERGY

BX IN SITU OIL SHALE PROJECT

Annual Technical Progress Report for Period March 1, 1979—February 29, 1980

Quarterly Technical Progress Report for Period December 1, 1979—February 29, 1980

By
Paul M. Dougan

March 20, 1980
Date Published

Work Performed Under Contract No. FC20-78LC10747

Equity Oil Company
Salt Lake City, Utah

U. S. DEPARTMENT OF ENERGY

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ANNUAL TECHNICAL PROGRESS REPORT
FOR MARCH 1, 1979 - FEBRUARY 29, 1980

AND

QUARTERLY TECHNICAL PROGRESS REPORT
FOR DECEMBER 1, 1979 - FEBRUARY 29, 1980

FE-78LC10747-11

Published March 20, 1980

Prepared For: U. S. DEPARTMENT OF ENERGY

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OBJECTIVE AND SCOPE OF WORK

The objective of this Project is to demonstrate the technical feasibility of using superheated steam as a heat carrying medium to retort in situ the oil shale in the Green River Formation "leached" zone and provide a mechanism for the recovery of this shale oil with a minimum impact on the environment. Utilizing primarily the natural porosity in the leached zone, approximately one trillion BTU of heat will be injected into a site over a 2-year period to heat to retorting temperature a shale zone approximately 550 feet thick and covering about 1 acre. The field Project is located at Equity's BX in situ site in Rio Blanco County in northwestern Colorado.

ABSTRACT

March 1, 1978 - February 29, 1980 is the third year of work on the BX In Situ Oil Shale Project. During the year, design, construction and installation of all Project equipment was completed, and continuous steam injection began on September 18, 1979 and continued until February 29, 1980. In the five-month period of steam injection, 235,060 barrels of water as steam at an average wellhead pressure of 1199 PSIG and an average wellhead temperature of 456°F. were injected into the eight Project injection wells. Operation of the Project at design temperature and pressure (1000°F. and 1500 PSIG) was not possible due to continuing problems with surface equipment. All laboratory research work associated with the Project was completed during the year and a final report on the work will be completed in the present quarter. Environmental monitoring at the Project site continued during startup and operations in compliance with the established Environmental Research Plan.

INTRODUCTION

This report covers work accomplished on the BX In Situ Oil Shale Project for the year ended February 29, 1980, and for the quarter ended that same date. By combining the fourth quarter report with the annual technical progress report, it is felt that a more comprehensive overview of the Project status will be accomplished. The status and progress during the year will be reported by Project Task.

VERTICAL COMMUNICATION TEST (B00)

During May and June, a series of drawdown and injection tests were run to further characterize the horizontal and vertical permeability in the leached zone. The tests were designed and directed by Walter W. Loo of VTN, Inc. A report by Mr. Loo detailing the results of the tests is included as Appendix "A" to this report.* The results of the tests and Loo's recommendations are summarized as follows:

SUMMARY

1. The leached zone or lower aquifer in the BX well field area is anisotropic.
2. The ratio of major horizontal permeability, minor horizontal permeability and vertical permeability in the leached zone is 14.7:13.3:1 respectively or 199md:180md:13.5md.
3. The average horizontal transmissivity of the leached zone is 1809 gpd/ft. with an upper leached zone value of 987 gpd/ft. and a lower leached zone value of 922 gpd/ft.
4. The average horizontal permeability of the leached zone is about 189md.
5. The average storage coefficient is about 1.54×10^{-3}

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*This report was presented at the Ninth Annual Rocky Mountain Groundwater Conference in Reno, Nevada, on October 22, 1979.

for the leached zone.

6. The average horizontal permeability in the upper injection horizon, production horizon, and lower injection horizon in the leached zone are 308md, 70md, and 308md, respectively.

7. The rate of ground water movement in the leached zone is about 23.4 feet per year due north across the BX In Situ Oil Shale Project site.

8. The contrast of horizontal to vertical permeability is large. It will cause unsatisfactory vertical sweep by the present well perforation designs.

RECOMMENDATIONS

Since the three-dimensional geohydrologic properties of the "leached" zone have been determined, it is possible to provide meaningful input data into any valid reservoir models. A reservoir model which can handle both the horizontal and vertical permeability is recommended. The horizontal anisotropic property of the leached zone will not be a significant factor in controlling the flow of fluid. The selected model should be able to handle high temperature geochemistry thermodynamics, multiple-phase fluid flow, and general printed and plotting capabilities. With the on-going steam injection activity and data logger capability, the model should utilize this data for model calibration and fitting purposes. Once the model is calibrated, projection can be made on production curves and other simulation uses. With added on optimization technique to the model, cost of production well field can then be reduced to a minimum.

Of primary interest to the Project operation is the ratio of major horizontal permeability and vertical permeability of 14.7:13.3:1 or 199md:180md:13.5md. This indicates that fluid flow at the Project site should be basically isotropic in the horizontal component, but that the ratio of 14.35:1 for horizontal to vertical permeability will make operation of the Project more difficult.

In this regard, it should be noted that the effects of injection in the injection wells when coupled with drawdown and production from the producing wells should significantly enhance the vertical flow of injected fluids but the extent of this effect will only be known as the Project proceeds.

Following initial steam injection from June 11th through June 24th, temperature and spinner surveys were run in the injection wells to assess the degree that both upper and lower perforations in the injection wells were, in fact, accepting steam and to determine if the insulation on the injection tubing was functioning properly.

Differential temperature logs were run in all injection wells and spinner surveys were run in BX-30, BX-32 and BX-33. With the exception of BX-30, (Injection Well #3) the logs showed relatively uniform injection in both the upper and lower injection zones and indicated a 2-1/2 to 5°F. temperature loss per 100 feet. For example, in BX-17 while injecting at 279°F. and a rate of 450 barrels of water per day, the recorded temperature at 1335 feet was 234°F. (Figure No. 1 is a plot showing the relationship of injection, production, and temperature observation wells.)

A summary of results of the temperature and spinner surveys is included as Appendix "B" to this report.

The surveys run on BX-30 indicated no injection below a depth of 860 feet (see Appendix "B").

Continued monitoring of injection into BX-30 showed it to be the poorest injector, and in October 1979, it was cleaned out and reperforated to improve injectivity. Results of this work are reported under task (G00).

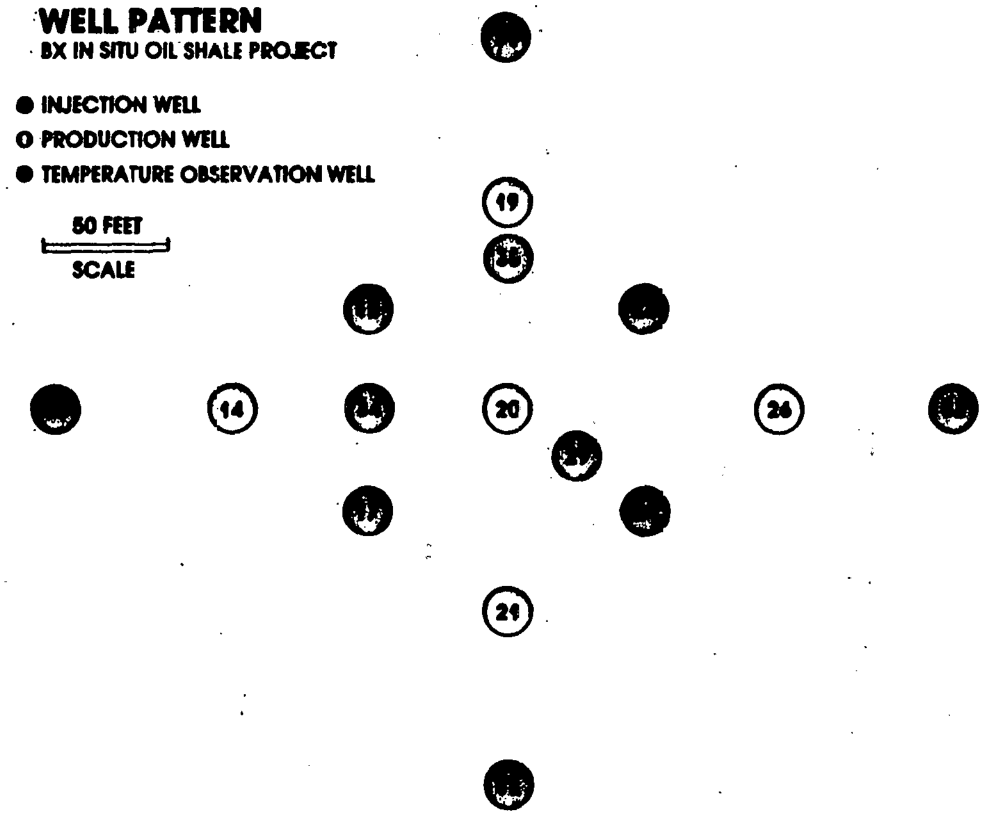

WELL PATTERN
BX IN SITU OIL SHALE PROJECT
INJECTION WELL
PRODUCTION WELL
TEMPERATURE OBSERVATION WELL
50 FEET
SCALE
19
14
20
26
21

Figure No. 1

Directional surveys have been run on all Project wells. The well bore traces of the wells have been plotted and a map showing the bottom-hole locations of each of the Project wells is included as Appendix "C" to this report. On the map dashed lines depict the true vertical trace each well bore should have followed, and the solid lines indicate the actual well bore trace.

LABORATORY EXPERIMENTATION (C00)

During the year, all experiments to be conducted under the laboratory research program were compled, and at year end, the data derived from the experiments was being reduced for inclusion in a final report detailing the results of the laboratory research program.

The major work of the program consisted of a series of eleven retorting runs utilizing superheated steam at varying temperatures and pressures to retort oil shale from the leached zone which had been packed in a 6" diameter sixteen-foot long retort.

The work has shown that the pressure and temperature used in retorting appears to have very little effect on the quality of the evolved oil. The most influential factor affecting the yield and quality of the evolved oil seems to be thr esidence time of the evolved oil in the steam retorting environment. Tables I and II summarize data from the eleven retorting runs, and Appendix "D" is a detailed annual report on the laboratory retorting program. Present work is focused on reducing data derived from the experiments and characterizing the oil produced from the experiments. On February 28, 1980, a meeting was held at the Flammability Research Center with Dr. Jacobs, Paul Dougan, Dr. Hill, Bill McFarlane and Leonard Wocik.

Table I

RETORTS Equity Oil Experiments	DURATION(HR)	PRESSURE	AVERAGE FLOW RATE	CHARACTERISTICS (1) Origin (2) Fisher Assay (3) Size	VESSEL DATA (1) Material Used, Void Fraction (2) Original-Final Weights,% Change (3) Inlet-Outlet Max. Temperatures(°F)
1	3.33	250 PSIG 1.724 MPa	200 to 300 LBS/HR 91 to 136 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Gravel,N.A. Gravel,N.A. Shale,N.A. 78.5-78.5,0% 81.0-81.0,0% 77.0-77.0,0% 49.5-49.0,1% 754°-N.A. N.A.-N.A. N.A.-N.A. 529.7°-471.5°
2	6.17	270 PSIG 1.862 MPa	200 to 300 LBS/HR 91 to 136 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Gravel,N.A. Shale,N.A. 78.5-78.5,0% 77.0-77.0-0% 49.5-39.2,20.8% 1019°-N.A. N.A.-N.A. 860°-809° (Same Shale as First Experiment)
3	28.00	270 PSIG 1.862 MPa	40.1 LBS/HR 18.2 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,N.A. Shale,N.A. 78.5-78.5,0% 52-40,23% 50-49,2% 965°-N.A. 809°-724° 705°-643°
4	26.50	570 PSIG 3.930 MPa	51.9 LBS/HR 23.5 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,N.A. Shale,N.A. 78-78,0% 54.0-42.5,21.7% 53-45,14.8% 950°-N.A. 813°-741° 720°-663°
5	11.50	300 PSIG 2.068 MPa	78.1 LBS/HR 35.4 Kg/HR	Equity BX-12 L.A. Various Sizes	Gravel,N.A. Shale,40.8% Instrumented Shale Piece 78.5-78.5,0% 57.0-49.9,12.5% 967°-N.A. 868°-796° 794°
6	21.25	250 PSIG 1.725 MPa	68.6 LBS/HR 31.1 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,51.0% Shale,45.3% Sand,37.0% 78.5-78.5,0% 57.1-45.3,20.7% 56.7-47.2,16.8% 76.0-74.5,2.0% 971°-N.A. 886°-833° 823°-771° 763°- 724°
7	117.25	320 PSIG 2.206 MPa	39.8 LBS/HR 18.0 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,47.3% Shale,48.4% 78.5-78.5,0% 52.2-42.6,18.4% 51.3-46.5,9.3% 868°-N.A. 732°-654° 652°-591°
8	101.00	300 PSIG 2.068 MPa	31.5 LBS/HR 12.6 Kg/HR	Equity BX-12 L.A. Various Sizes	Shale,46.5% Shale,50.6% Glass Wool, N.A. 56.0-50.1,10.5% 54.5-51.4,5.7% N.A. 761°-636° 621°-565° 560°-539°
9	17.00	250 PSIG 1.724 MPa	67.8 LBS/HR 30.7 Kg/HR	Equity BX-12 L.A. Various Sizes	Shale,44.0% Shale,45.9% Glass Wool,90.8% 50.6-42.0,17.0% 51.5-45.5,11.6% N.A. 1006°-900° 881°-832° 820-785°
10	18.00	570 PSIG 3.930 MPa	50.5 LBS/HR 22.9 Kg/HR	Equity BX-12 L.A. Various Sizes	Shale, N.A. Shale,N.A. Glass Wool,N.A. Glass Wool, N.A. 54.5-44.2,18.9% 58.6-45.6,6.8% N.A. N.A. 900°-784° 761°-665° 634°-594° 478°-395°
11	24.00	270 PSIG 1.862 MPa	50.1 LBS/HR 22.7 Kg/HR	Equity BX-13 L.A. Various Sizes	Shale,45.4% Shale,47.4% Glass Wool, N.A. Glass Wool, N.A. 49.9-40.2,19.5% 55.2-48.1,12.8% N.A. N.A. 960°-N.A. 761°-666° 635°-410° N.A.-N.A.
12	21.00	270 PSIG 1.862 MPa	51.6 LBS/HR 23.4 Kg/HR	Equity BX-13 L.A. Various Sizes	Shale,N.A. Shale,N.A. Empty Empty 56.3- 47.2, 16.3% 60.2-51.3,15.1% 946°-817° 795°-714° 543°-537° 537°-536°

N.A. = Not Available
L.A. = List Available
* = Estimated Value

Table II

RETORTS Equity Oil Experiments	OIL DATA (1) Amount Produced,% Fisher Assay (2) Pour Point Temperature (3) API Gravity	Gases Produced	CHEMICAL ANALYSIS ON OIL C	H	N	O S (Wt %)	C/H
1	No oil produced	0					
2	N.A.,85% 70°F,(21.1°C) N.A.	60.0 c.f.	83	12.2	1.4	3.4*1	6.80
3	N.A. 65°F,(18.3°C) N.A.	55.0 c.f.	81.7	11.6	2.0	4.7*1	7.04
4	9.67Lbs(4.39Kg),85% 69°F,(20.6°C) 21.80	109.5 c.f.	83.8	12.1	1.9	2.2*1	6.93
5	6.08Lbs(2.76Kg),98.9% 67°F,(19.4°C) 26.95	N.A.	82.4	12.0	2.2	3.4*1	6.87
6	8.70Lbs(3.97Kg),69.5% 68°F,(20.0°C) 23.80	90.2 c.f.	83.4	12.0	1.6	3.0*1	6.95
7	6.07Lbs(2.75Kg),58.4% 71°F,(21.7°C) 26.60	N.A.	82.3	11.9	1.4	4.4*1	6.92
8	3.59Lbs(1.63Kg),34.6%* 58°F,(14.4°C) 25.40	N.A.	81.7	12.0	1.4	4.9*1	6.81
9	7.25Lbs(3.29Kg),98.0% 51°F,(10.6°C) 25.90	101.8 c.f.	82.4	11.9	1.9	3.8*1	6.92
10	5.10Lbs(2.31Kg),56.5% 27°F,(-2.78°C) 28.57	64.6 c.f.	82.9	12.2	1.7	3.2*1	6.80
11	5.76Lbs(2.61Kg),53.8% 27°F,(-2.78°C) 26.95	93.5 c.f.	84.6	13.0	1.4	0.9*1	6.51
12	4.51Lbs(2.05Kg),47.7% 41°F,(5.00°C) 26.60	85.4 c.f.	83.4	12.7	1.4	2.5*1	6.57

N.A. = Not Available
* = Estimated Value
1 = Combined O and S

TII-1

PROCESS	NAPTHA IBP to 400°F IBP to 204°C	LIGHT DISTILLATE 400°F to 600°F 204°C to 316°C	LIGHT GAS OIL 600°F to 800°F 316°C to 427°C	HEAVY GAS OIL 800°F to 1000°F 427°C to 538°C	RESIDUUM Over 1000°F Over 538°C
Steam Retort 11	33.7	58.3	6.1	1.9	0
Bottom Burning	40	45	4.6	1.8	8.6
Hill & Dougan	45	35	12	6	2
IITRI	45	23	6	26	-
Arabian Light	36	23	17	17	7
Steam Retort 4	13.7	45.7	40.1	0.5	0
Tosco	22	32	17	11	18
Garret	18	45	20	13	4
Paraho	8	44	20	19	9

Table 3: Comparison of Distillation Properties From Various Retorting Processes. (Non-steam retorting data from references 1 and 5)

TII-2

RETORTS	OIL DATA (3) Amount Produced,% Fisher Assay (2) Pour Point Temperature (3) API Gravity	Gases Produced	CHEMICAL ANALYSIS ON OIL C	H	N	O	S (Wt %)	C/H
Steam Retort 11	5.76Lbs(2.61Kg),53.8% 27°F,(-2.78°C) 26.95	93.5 c.f.	84.6	13.0	1.4	0.9*1		6.51
Bottom Burning	N.A.,65% 68°F,(20.0°C) 31.70	N.A.	84.1	11.9	2.1	1.9*1		7.08
Hill & Dougan	N.A. -4°F,(-20.0°C) 40.00	N.A.	N.A.	N.A.	0.8	N.A.		N.A.
IITRI	N.A.,96% 40°F,(4.44°C) 34.40	N.A.	84.0	12.1	1.0	2.8	.6	6.94
Arabian Light	N.A. N.A. 34.40	N.A.		N.A.				N.A.
Steam Retort 4	9.67Lbs(4.39Kg),85% 69°F,(20.6°C) 21.80	109.5 c.f.	83.8	12.1	1.9	2.2*1		6.93
Tosco	N.A. 70°F,(21.1°C) 20.98	N.A.		N.A.				N.A.
Garret	N.A. 85°F,(29.4°C) 19.35	N.A.		N.A.				N.A.
Paraho	N.A. 50°F,(10.0°C) 25.03	N.A.		N.A.				N.A.
Marathon Oil Batch	N.A. 82°F,(27.8°C) 20.40	N.A.	84.0	11.2	1.7	1.6	.8	7.50
Continuous Flow	N.A. 74°F,(23.3°C) 21.10	N.A.	83.3	11.0	1.8	2.6	.8	7.57
Equity Field Site	N.A. N.A. N.A.	N.A.	74.8	12.0	0.6	12.6*1		6.23

N.A. = Not Available
* = Estimated Value
1 = Combined O and S

TII-3

The purpose of the meeting was to decide which product oil (that is, from which retorting runs) should receive detailed analysis, and what that analysis should entail.

It was decided that oil from Retorting Runs No. 3 and No. 11 will be analyzed in detail and compared with samples obtained from the field Project and with similar data from other synthetic crudes and natural crudes. The comparison of the oils will include the following analysis:

Identification of Specific Species
Solvent Fractination
Polarity Measurements
C H N O S Analysis
Pour Point
Gravity
TGA Analysis (Boiling Point)

BX PROJECT INJECTION AND PRODUCTION WELLS (F00) & (G00)

At the completion of Project construction eight steam injection wells and five production wells were in place. (Refer to Figure 1.) These wells were completed in the fashion shown in Figure No. 2. The difference between the injection and production wells are that the injection well production casinq is larqer in diameter, 8-5/8" vs. 7", and the injection well tubing strings are insulated with 1½ inches of temp mat insulation covered with a rolled stainless steel jacket pop riveted in place while the production tubing strings are uninsulated. Also, injection wells are perforated at the top and bottom of the leached zone while the production wells are perforated at the middle of the leached zone.

Project design calls for maximum total pattern injection of 46,000 lbs/hour (131.43 BBL/hr) of superheated steam at 1500 PSIG and 1000^{O}F. This is equivalent to an average per well rate of 5750 lbs/hour or 16.43 BBLs/hour.

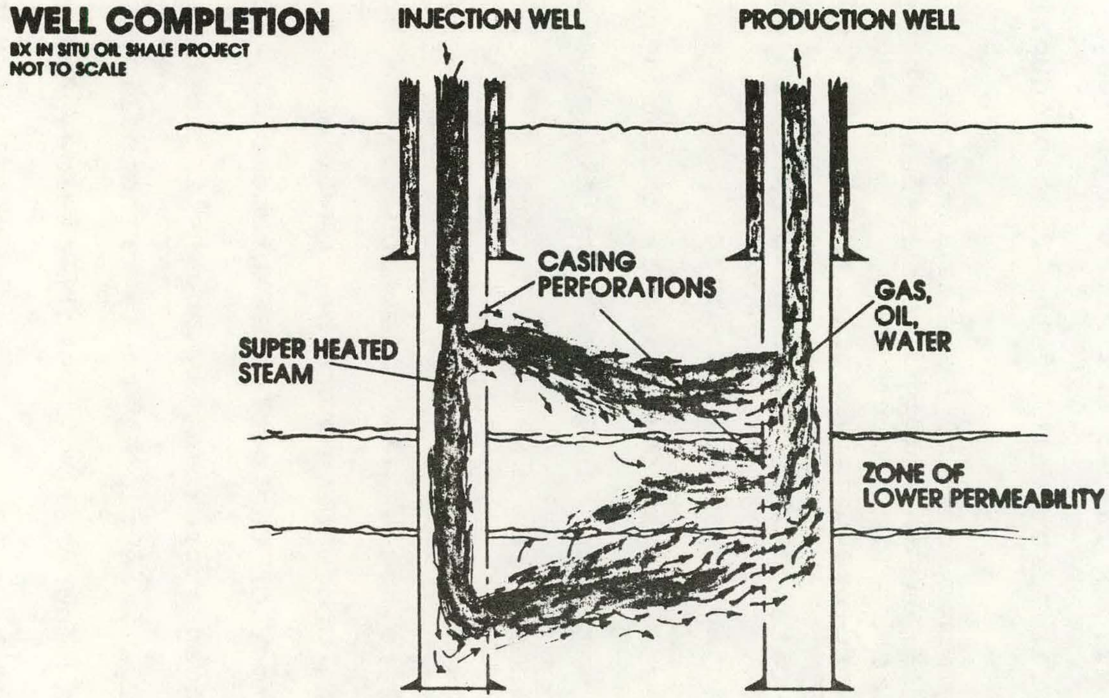

WELL COMPLETION
BX IN SITU OIL SHALE PROJECT
NOT TO SCALE
INJECTION WELL
PRODUCTION WELL
CASING
PERFORATIONS
GAS,
OIL,
WATER
SUPER HEATED
STEAM
ZONE OF
LOWER PERMEABILITY

Figure No. 2

Feed water requirements to support this maximum rate are approximately 1.3 times the amount of water being injected as steam since the steam generators operate at 80% quality, and water is required for water softener regeneration and for backwash of the water filter. This amounts to a maximum total pattern daily water production requirement of 4,100 barrels per day (1.3 x 131.43 bbl/hr. x 24 hr/day) or an average daily production rate from each of the five production wells of 820 barrels per day.

At the initiation of steam injection, it was felt that the completion of the injection and production wells would accommodate these injection and production rates. This match of production equalling approximately 1.3 times injection is an essential part of the successful development of the process since by operating in that mode, there will be no consumptive use of water in the process and all process needs will be met by water produced from the leached zone.

Data to date as illustrated in Table III and Figures 3, 4, 5, 6, 7 and 8 indicate that 50% to 65% of the injection goal is being met on a continuous basis but the production rate has never exceeded the injection rate and, for most of the period (September 18, 1979 - February 29, 1980), has been approximately one-half the injection rate.

Not meeting the design injection rate is principally a result of equipment problems but is secondarily a result of low production. The steps taken during the year to aid injection and production included:

BX In Situ Oil Shale Project
Production / Injection Summary
September 1979 - November 1979

Table III

DATE	0 (BX-19)	1 (BX-26)	2 (BX-20)	3 (BX-14)	4 (BX-21)	Injection Pressure	Total Production	Total Injection
9-18-79	106					771	609	778
9-19-79	159					995	897	1879
9-20-79	149					1028	265	1841
9-21-79	122					997	732	2105
9-22-79	96					1010	524	2867
9-23-79	133					1338	796	2295
9-24-79	140					1385	735	2443
9-25-79	129					1381	785	2499
9-26-79	122					1391	722	2499
9-27-79	123					1398	774	2562
9-28-79		254				1372	647	2426
9-29-79		322				1370	671	2389
9-30-79			79			1360	750	2623
10-1-79			74			1369	765	2477
10-2-79				108		1351	765	2388
10-3-79				63		1271	720	2241
10-4-79				134		1347	760	2425
10-5-79				134		1365	613	2461
10-6-79				145		DATA LOST	841	DATA LOST
10-7-79				130		604	791	1584
10-8-79	DATA LOST							
10-9-79				127		1340	774	2461
10-10-79					105	1364	698	2278
10-11-79					87	1389	635	2278
10-12-79					102	1380	771	2285
10-13-79					82	1414	748	2204
10-14-79	DATA LOST							
10-15-79		32				1367	730	2278
10-16-79						1125	671	1874
10-17-79		71				1257	374	1800
10-18-79			107			1281	761	1652
10-19-79			102			1314	761	1580
10-20-79			98			1329	767	1690
10-21-79			96			1378	749	1911
10-22-79			NO DATA			1075	NO DATA	1580
10-23-79			147			1201	484	1580
10-24-79			192			1148	647	1690
10-25-79			211			NO DATA	845	829

BX In Situ Oil Shale Project
Production / Injection Summary
September 1979 - November 1979

DATE	0 (BX-19)	1 (BX-26)	2 (BX-20)	3 (BX-14)	4 (BX-21)	Injection Pressure	Total Production	Total Injection
10-26-79			207			1130	860	1680
10-27-79			202			1162	868	1296
10-28-79			209			1245	788	1440
10-29-79			195			1304	907	1503
10-30-79				97		1339	741	1508
10-31-79				70		1321	707	1457
11-1-79						1340	599	1440
11-2-79						1281	511	1076
11-3-79						1190	781	1231
11-4-79						1341	790	1199
11-5-79						1330	737	1204
11-6-79				64		1302	694	1233
11-7-79				89		1272	733	1193
11-8-79					117	1189	673	921
11-9-79					103	NO DATA	644	NO DATA
11-10-79	69					899	536	911
11-11-79	48					819	307	747
11-12-79						947	91	834
11-13-79						1005	24	830
11-14-79	52					983	100	733
11-15-79	52					1037	110	810
11-16-79	40					1044	58	278
11-17-79		NO INJECTION ON THIS DAY.					58	
11-18-79		NO INJECTION ON THIS DAY.					40	
11-19-79		NO DATA 5 hrs. operation only.						
11-20-79		19				597	24	983
11-21-79		All production shut in preparing to fracture all						
11-22-79		production wells and BX-30.				912	0	1280
11-23-79						1006	0	1242
11-24-79						1051	0	1204
11-25-79						1091	0	1255
11-26-79						1118	0	1394
11-27-79		44				1150	55	1082
11-28-79		817				908	817	1157
11-29-79		342				884	345	833
11-30-79						884		1085

BX In Situ Oil Shale Project
Production / Injection Summary
December 1979 - February 1980

DATE	0 (BX-19)	1 (BX-26)	2 (BX-20)	3 (BX-14)	4 (BX-21)	Injection Pressure	Total Production	Total Injection
12-1-79						990	568	1256
12-2-79						NO DATA	476	580
12-3-79						1075	870	1852
12-4-79				106		1209	744	2219
12-5-79		214				1328	913	1744
12-6-79					151	1232	321	1291
12-7-79					328	1322	328	1125
12-8-79					271	1354	271	1101
12-9-79					18	NO DATA	18	1349
12-10-79					205	1364	780	1089
12-11-79					214	1266	885	1099
12-12-79					329	1355	787	1133
12-13-79					291	1355	1019	1117
12-14-79					270	1310	625	1107
12-15-79					262	1235	773	1194
12-16-79	132					1222	570	1193
12-17-79	125					1239	228	1259
12-18-79	36					1296	265	1240
12-19-79	0					1321	86	1174
12-20-79	33					1126	33	1103
12-21-79	83					1173	83	1082
12-22-79	164					1079	164	1013
12-23-79	56					1047	61	564
12-24-79	211					1040	480	1020
12-25-79	0					1088	412	1001
12-26-79	0					1145	363	1086
12-27-79		332				1150	590	1044
12-28-79		570				1166	852	1070
12-29-79		413				1201	955	1192
12-30-79		302				1217	912	1387
12-31-79		409				1262	1367	1416
1-1-80					277	1267	1090	1383
1-2-80					200	1273	815	1370
1-3-80					222	1251	1272	1381
1-4-80				252		1119	1125	1408
1-5-80				320		1125	1127	1414

BX In Situ Oil Shale Project
Production / Injection Summary
December 1979 - Feburary 1980

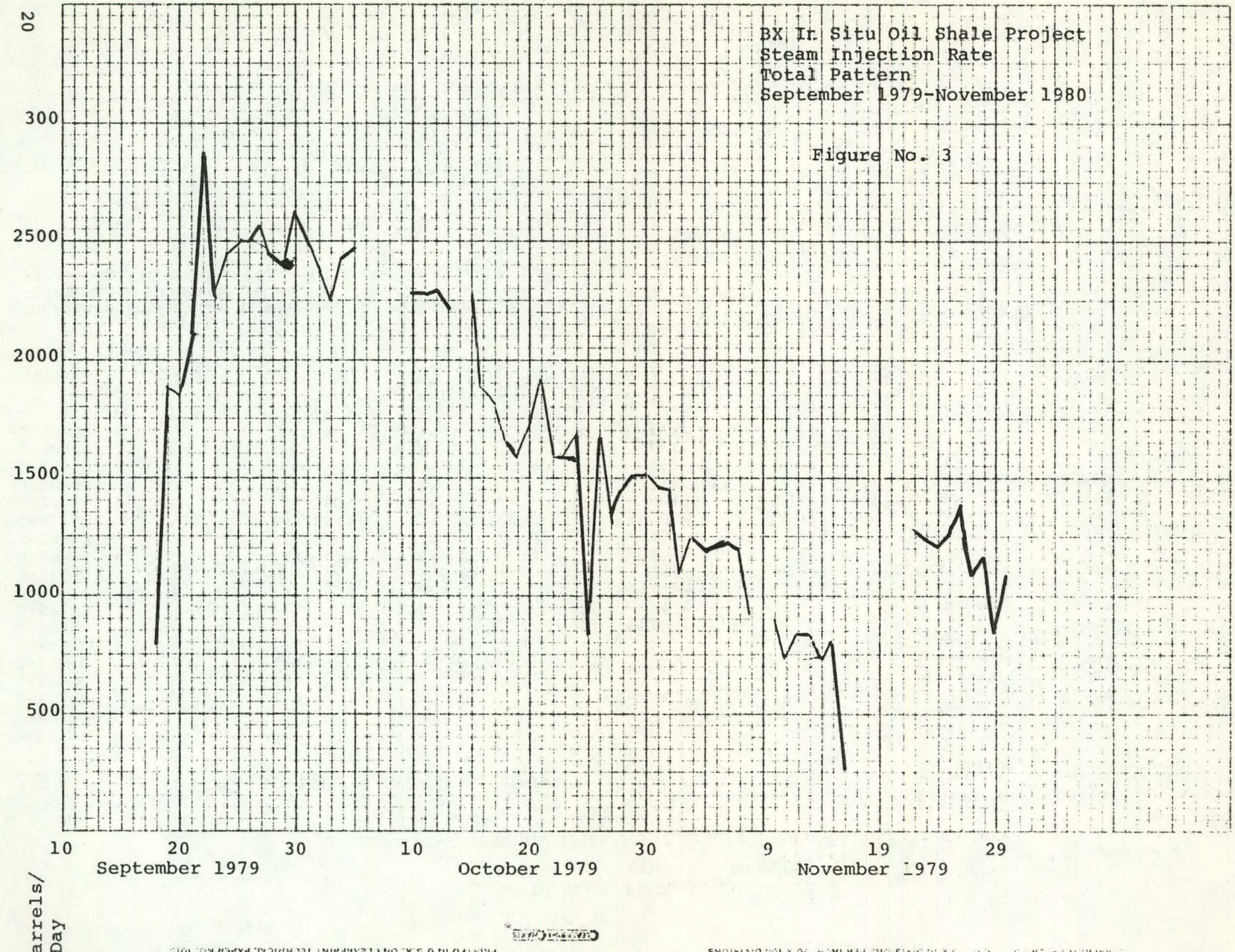
DATE	0 (BX-19)	1 (BX-26)	2 (BX-20)	3 (BX-14)	4 (BX-21)	Injection Pressure	Total Production	Total Injection
1-6-80				132		1145	811	1269
1-7-80				143		1334	690	1183
1-8-80				279		1346	956	1183
1-9-80				273		1369	1164	1183
1-10-80				260		1384	1186	1207
1-11-80				264		1363	1147	1159
1-12-80	258					1392	1119	1187
1-13-80	184					1366	1070	1402
1-14-80	189					1186	1035	619
1-15-80	104					1251	948	1291
1-16-80	102					1276	930	1396
1-17-80	202					1251	1063	1385
1-18-80		342				1030	886	1068
1-19-80				217		1227	870	1247
1-20-80					655	1250	847	1369
1-21-80	14					1272	844	1420
1-22-80	11					1263	842	1396
1-23-80	11					NO DATA	834	890
1-24-80	11					1224	829	1444
1-25-80	26					1222	860	1501
1-26-80	83					1240	867	1447
1-27-80	11					1254	807	1446
1-28-80				102		1252	800	1380
1-29-80				157		1276	955	1390
1-30-80					93	1267	380	1510
1-31-80				6		1136	876	907
2-1-80					193	1171	832	909
2-2-80					146	1129	743	1139
2-3-80					128	1247	732	1305
2-4-80					216	1290	799	1579
2-5-80	218*			181*	92	1352	662	2078
2-6-80				235		1389	727	1946
2-7-80	191*			240/251*		1248	586	1059
2-8-80	244*			241/219*		1180	693	1149
2-9-80	250*			249/316*		1383	849	2173
2-10-80	204*			240/182*		1434	784	2020
2-11-80			177			1407	766	1752

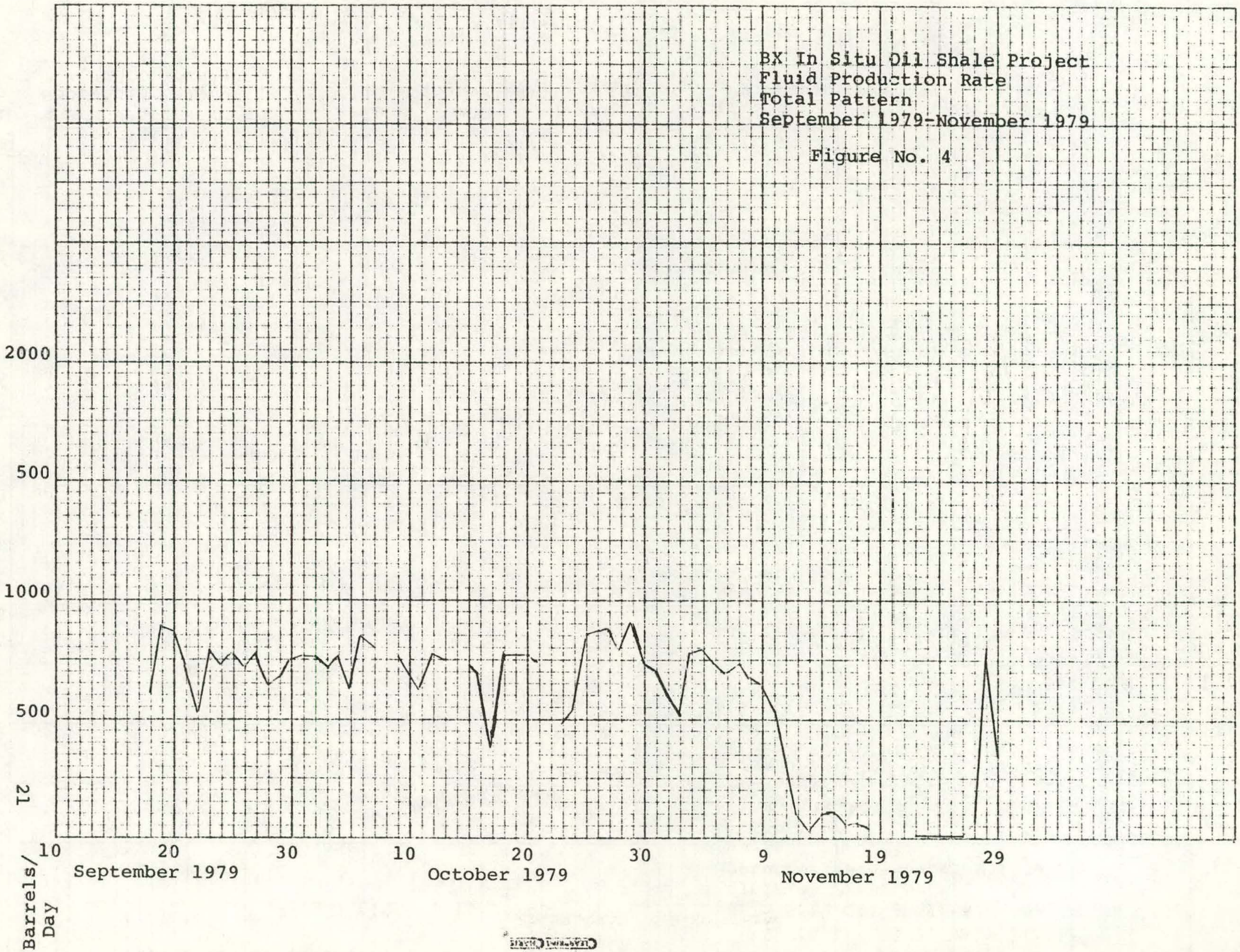
BX In Situ Oil Shale Project
Production / Injection Summary

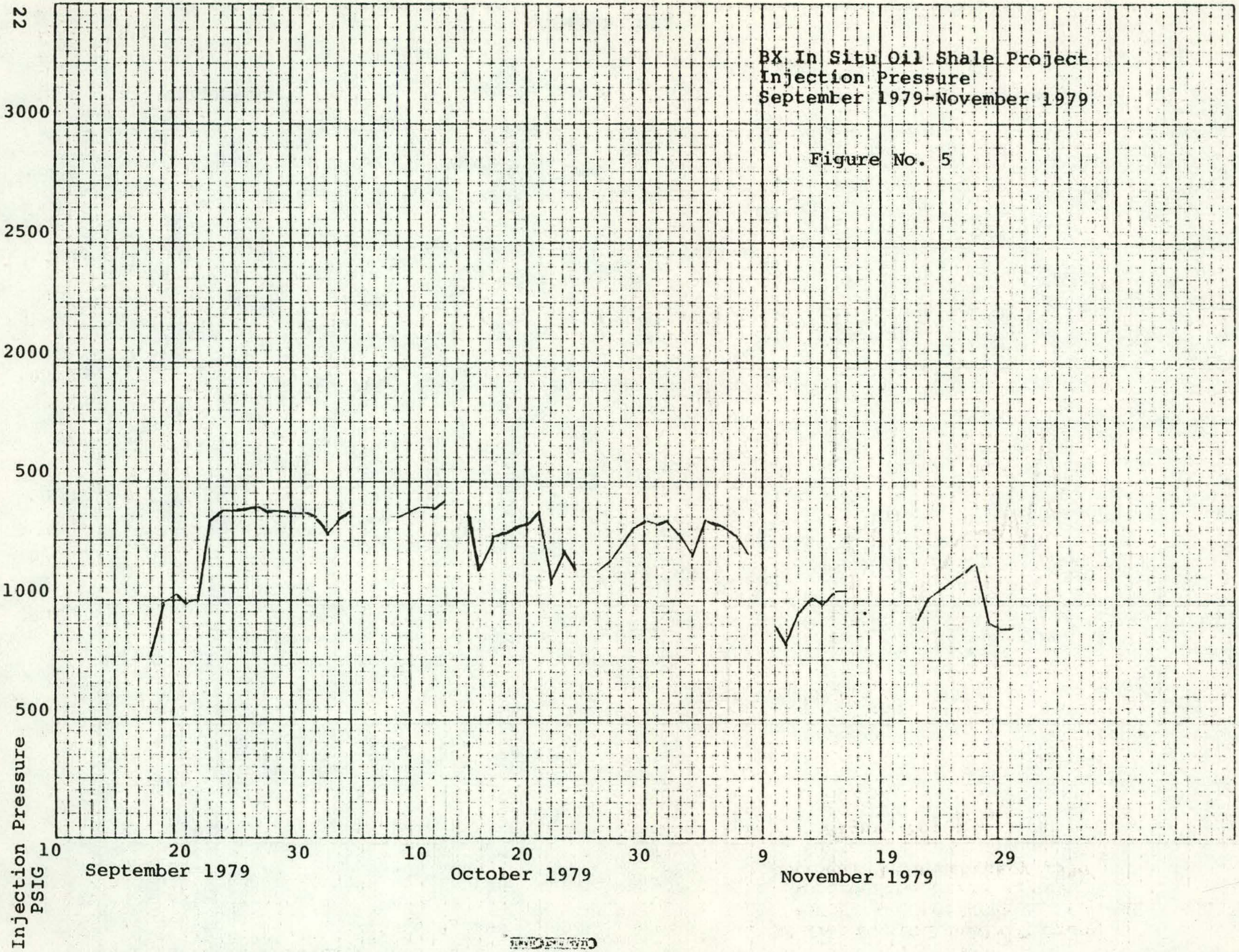
December 1979 - February 1980

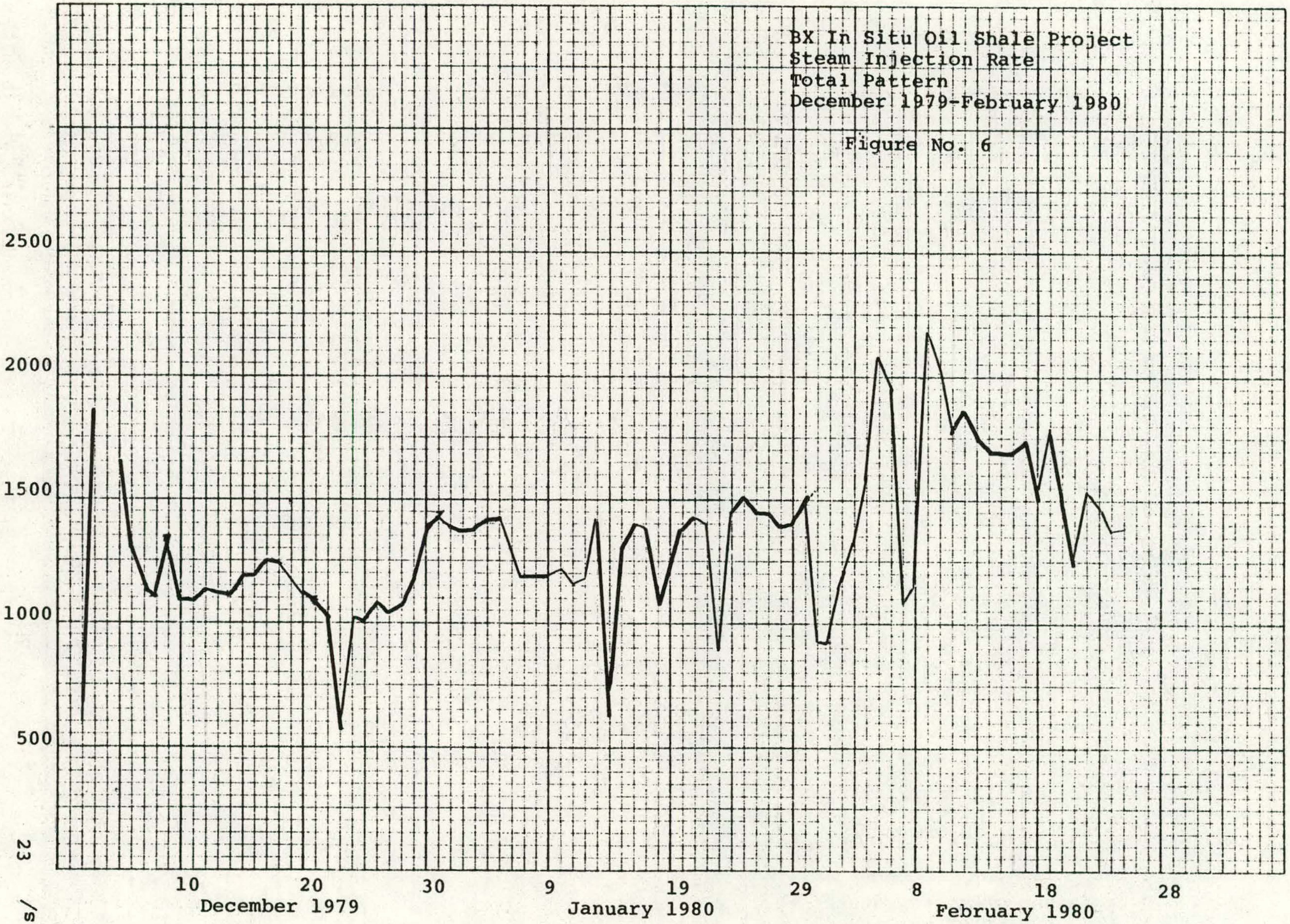
DATE	0 (BX-19)	1 (BX-26)	2 (BX-20)	3 (BX-14)	4 (BX-21)	Injection Pressure	Total Production	Total Injection
2-12-80			40			1446	785	1857
2-13-80			32			1426	809	1749
2-14-80			8	207*		1435	787	1695
2-15-80	198*		21			1443	780	1686
2-16-80	198*		4	63*		1446	735	1696
2-17-80	195*		0			1434	722	1737
2-18-80	198*		0	125*		1434	719	1509
2-19-80	201*	199		67*		1423	727	1784
2-20-80	195*	302/321*		88*		1424	702	1473
2-21-80		309/276*		247*	189*	1373	724	1235
2-22-80	188*	229*		252*	256/305*	1445	831	1794
2-23-80	202*	233*		410*	227/229*	1451	895	1703
2-24-80	165/164*	227*		303*	263*	1452	839	1620
2-25-80	145/268*	251*		414*	287*	1455	908	1634
2-26-80	326*	243*		259/301*	305*	1438	949	1631
2-27-80	281*	242*		205/122*	327*	1412	877	1640
2-28-80	218*	293/321*		182*	379*	No data	684	No data
2-29-80	214*	293*	4	392*	90*		736	

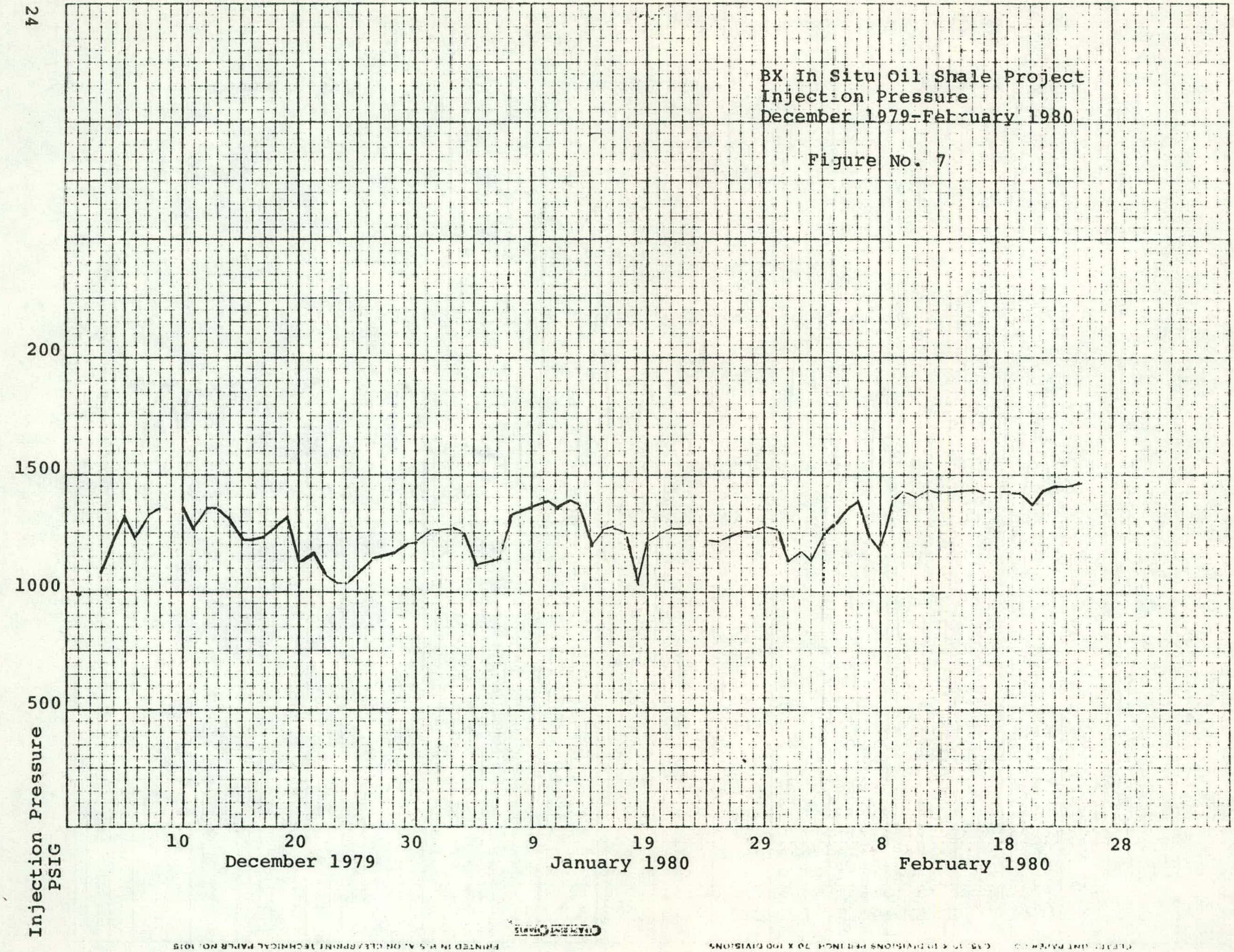
*Readings taken from production survelliance monitors.
**Injection pressure in PSIG.
***Production & injection rates are in barrels/day.

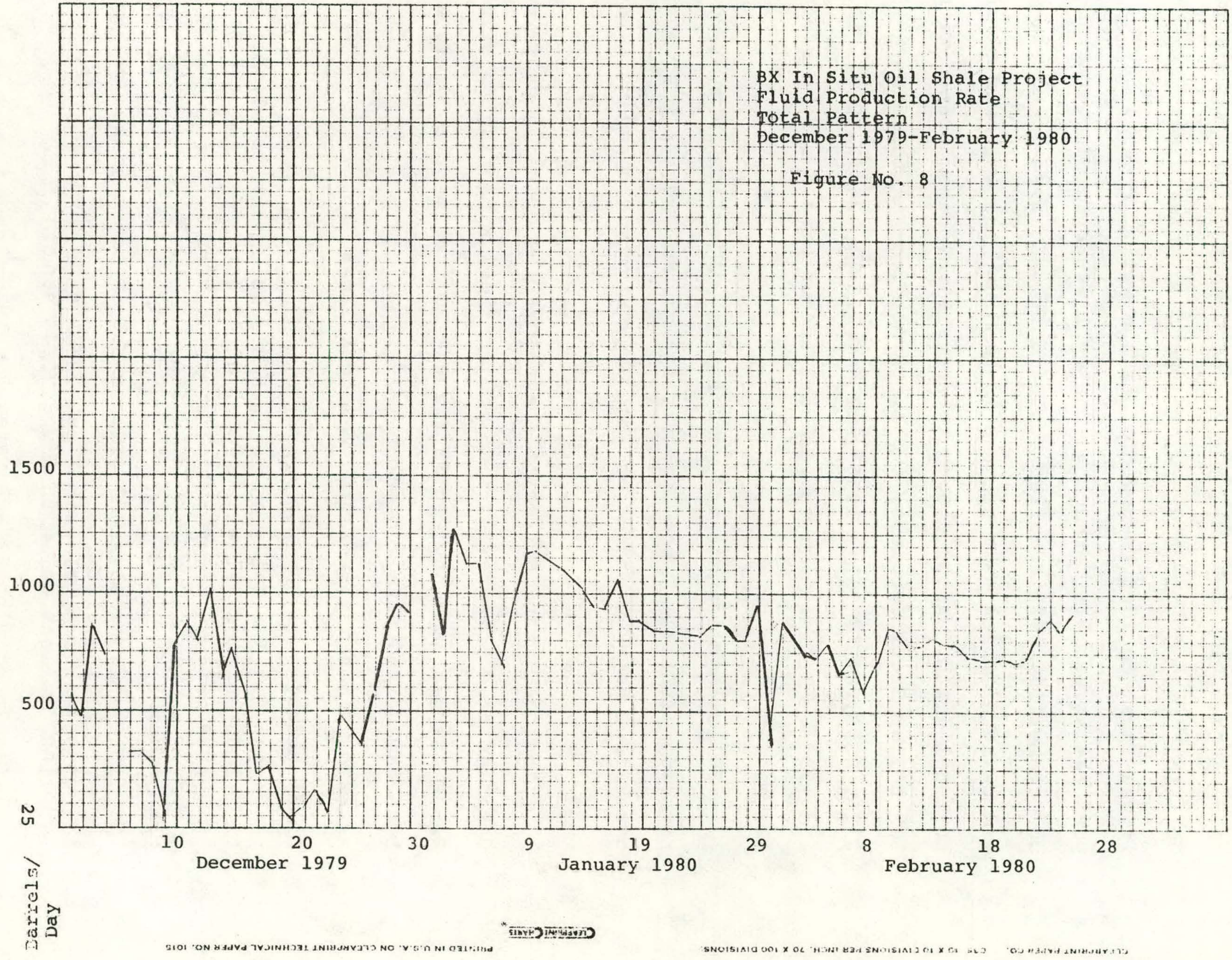

BX In Situ Oil Shale Project
Steam Injection Rate
Total Pattern
September 1979-November 1980
Figure No. 3
20
300
2500
2000
1500
1000
500
10
20
30
10
20
30
9
19
29
September 1979
October 1979
November 1979
Barrels/
Day


BX In Situ Oil Shale Project
Fluid Production Rate
Total Pattern
September 1979-November 1979
Figure No. 4
2000
500
1000
500
Barrels/Day
10
20
30
10
20
30
9
19
29
September 1979
October 1979
November 1979


BX In Situ Oil Shale Project
Injection Pressure
September 1979-November 1979
Figure No. 5
3000
2500
2000
500
1000
500
Injection Pressure
PSIG
10
20
30
10
20
30
9
19
29
September 1979
October 1979
November 1979


BX In Situ Oil Shale Project
Steam Injection Rate
Total Pattern
December 1979-February 1980
Figure No. 6
2500
2000
1500
1000
500
10
20
30
9
19
29
8
18
28
December 1979
January 1980
February 1980
Barrels/ Day


BX In Situ Oil Shale Project
Injection Pressure
December 1979-February 1980
Figure No. 7
200
1500
1000
500
Injection Pressure
PSIG
10
20
30
9
19
29
8
18
28
December 1979
January 1980
February 1980



BX In Situ Oil Shale Project
Fluid Production Rate
Total Pattern
December 1979-February 1980
Figure No. 8
1500
1000
500
25
Barrels/
Day
10
20
30
December 1979
9
19
29
January 1980
8
18
28
February 1980

BX-30 (Injection Well No. 3)

BX-30 (Injection Well No. 3) has been the poorest injection well in terms of injectivity. To overcome this injectivity problem it was first decided to reperforate the well. Preparatory to the perforating, it was found that the well was bridged over at 846 feet. On October 17, 1979 a coiled tubing unit was moved on to the well, and using nitrogen as a circulating medium, the well was cleaned out to total depth. After cleanout the well was reperforated with 1 9/16" SSB Hollow Steel Carriers, two shots per foot as follows: 809', 812', 817', 835', 842', 851', 1230', 1236', 1239', 1249', 1255', 1270', 1288', and 1292'. The maximum temperature encountered during perforating was 246^{o}F.

Following cleanout and perforation, injection into BX-30 was resumed. Initially, the injectivity was much better. However, after four days of injection, the injectivity dropped to a very low rate.

The poor results from the reperforation of BX-30 prompted a decision at a November 3, 1979 Project review meeting to stimulate BX-30 using a small hydraulic fracturing treatment to overcome well bore damage and permit greater injection.

The planned stimulation was as follows:

First Stage

1500 gallons 40#/1000 gallons MYF-10 cross-linked gel
1000 gallons gel with 1 ppg. 20/40 sand
1000 gallons gel with 2 ppg. 20/40 sand

Second Stage

1500 gallons 40#/1000 gallons MYF-10 cross-linked gel with 30 ball sealers.
1000 gallons gel with 1 ppg 20/40 sand
1000 gallons gel with 2 ppg 20/40 sand

Displaced with 3% KCL water.

A total of 7000 gallons of MYF-10 and 6000 lbs. of 20/40 mesh sand were planned to be used in the treatment. Injection rates averaged 10.5 BBL/min at an average pressure of 950 PSIG.

The first stage of the treatment went as planned, however after the first stage, the Halliburton pump truck doing the job lost its prime and the well screened off. (The tubing loaded up with sand when the fluid stopped flowing). The total planned job could not be completed as a consequence of the "sand out", and the results of the stimulation of BX-30 are questionable.

Subsequent to this treatment, injectivity into BX-30 has been at times better than before, but it still remains the worst of the eight injection wells in terms of overall injectivity, averaging only 3.1% of the total average daily injection rate. Additional work to improve injectivity in this well is under consideration.

PRODUCTION WELLS

During April, production tests were run on each of the five production wells to determine their productivity using the installed gas lift system. Testing showed that in each well production was not as high as had been anticipated. The average rate for the five wells was 38 barrels per day per well.

It was initially determined that the low production rate was caused by two factors: (1) The wells had not been acidized following perforation and they were suffering from near well bore damage; and (2) the production tubing in each well was set at an average depth of 740 feet which did not allow full use of effects of the installed gas lift system.

To overcome these problems it was decided to acidize each of the production wells and to lower the tubing in each well.

Table IV | Table V

Form G-102 (7-62) 600M

WELL	FLOW TEST, BWPD INT. POT.	AFTER ACID	AFTER LOWERING TBG.	ACID TREATMENT BREAKDOWN AIR, BPM	T.P.	TREATMENT AIR, BPM	T.P.	T.S.I.P.	5 Min. SIP	REMARKS
BX-14	37	240	440	6	1500	6.5	1800	600	500	
BX-19	34	407	505	7.5	1800	6.5	1900	600	400	
BX-20	43	538	538*	7.2	1300	7.5	1900	1600	1200	Balled Out
BX-21	39	364	485	8.0	1800	8.0	1900	500	500	
BX-26	384**	460	545	8.0	1800	8.0	1900	500	300	
TOTAL	537	2009	2513							

*Could not lower tbg. because of 4½" liner.

**Well previously acidized.

***Acid consisted of: 3000 gallons 15% HCL and 6 gallons TRI-5 and 6 gallons HAI-55.

Table IV shows the production rate of the production wells before and after acidizing and after lowering the tubing. It was not possible to lower the tubing in well BX-20 because the 4½-inch casing liner in the well would not accomodate the gas lift valve on the end of the 2-3/8" tubing string. The average production rate after acidizing and lowering tubing was 503 barrels per day per well for a total production of 2513 barrels per day.

Table V summarizes the acidizing procedure used in each of the production wells.

Although initial production results following the acidizing indicated that production would be adequate to service the needs of the Project, after the first month of Project operation (September 18, 1979 to October 13, 1979) it was apparent that production was inadequate.

In an effort to determine the type of stimulation which would be required to increase productivity, it was decided to add additional perforations in BX-20 in an effort to broaden the production zone open in that well.

On October 17, 1979 perforations were added to BX-20 using 1 9/16" SSB Hollow Steel carriers two shots per foot as follows: 905'-911', 925'-934', 936'-943', 949'-958', 1180'-90', 1196'-1206', 1209'-1219', 1229'-1238'.

The addition of the perforations did not materially increase the productivity and it was decided to acidize the well.
The well was acidized on October 22, 1979 using 4000 gallons of regular mud acid; plus 4 gallons TRI-S plus 40 gallons of HC-2 surfactant and foaming agent; plus 12 gallons HAI-55 inhibitor;

using 225 ball sealers evenly spaced every eighteen gallons. The acid was injected at 5 BBL/min. at a maximum treating pressure of 1500 PSIG, and an average injection pressure of 800 PSIG.

The acidizing increased the well's production from a level of 100 barrels per day to 200 barrels per day. This was a significant increase, but production was still well below the average daily production of 800 barrels which will be required for maximum Project operations. It was clear that stimulation of this well and the other production wells would be required.

On November 3, 1979, a Project review meeting was held at Equity's office in Salt Lake City between Equity and DOE personnel to review Project progress and evaluate possible steps which could be taken to improve the steam injection capacity of the injection wells and the productive capacity of the production wells.

After reviewing the results with BX-20 and injection well BX-30, it was clear that additional stimulation of the production wells and possible the injection wells would be required to achieve Project injection and production goals.

The conclusion reached at the Project review meeting was that the principal deterent to both steam injection and fluid production was near well bore formation damage in the injection and production wells; and one method of overcoming the effects of this well bore damage would be the application of a small hydraulic fracturing treatment to the wells.

It was decided to proceed with the design and application of a hydraulic fracturing treatment for each production well and injection well No. 3 (BX-30) (as described above).

Accordingly, a treatment for the production wells and BX-30 was designed by Tom Wolter and Fred Reynolds with assistance from Halliburton Company, and on November 24, 1979 each well was fracced in two stages as follows:

<u>First Stage</u>

1500 gallons 40#/1000 gallons MYF-10 cross-linked gel
1000 gallons gel with 1 ppg. 20/40 sand
1000 gallons gel with 2 ppg. 20/40 sand

<u>Second Stage</u>

1500 gallons 40#/1000 gallons MYF-10 cross-linked gel with 30 ball sealers
1000 gallons gel with 1 ppg 20/40 sand
1000 gallons gel with 2 ppg 20/40 sand

Displaced with 3% KCL water.

A total of 7000 gallons of MYF-10 gel and 6000 lbs. of 20/40 mesh sand were used in the treatment. Injection rates averaged 10.5 BBL/min at an average pressure of 950 PSIG.

The frac program was designed to create a propped frac length of 24 feet with a fracture width of .126 inches. A fracture height of 400' was used in computing the fracture design.

The treatments of the production wells went as planned, however, the treatment of BX-30 was questionable due to the "sand-out" after the first stage of the treatment referred to above.

Initial indications were that the stimulation of the production wells had been beneficial, and that significant production increases in each of the production wells would be realized.

During the months of December 1979 - February 1980, the production was closely monitored and, although some gains in production were apparent, total average daily production at February 29, 1980 was insufficient to meet Project goals.

At the end of February specific 48-hour production test were run on each of the production wells with the following results:

WELL	1st 24 hrs.	2nd 24 hrs.	TOTAL 48 hrs.
*BX-19 (PW-0)	165 bbl	145 bbl	310 bbl
*BX-26 (PW-1)	302 bbl	309 bbl	611 bbl
*BX-14 (PW-2)	259 bbl	205 bbl	465 bbl
*BX-21 (PW-4)	256 bbl	227 bbl	483 bbl
**BX-20 (PW-5)	4 bbl		

*Wells are producing using gas lift system.
**Well on rod pump.

The continuing lack of production is not tolerable and alterations to the production well completion will be proposed at a Project Review Meeting to be held in Laramie on March 6th.

DESIGN/INSTALLATION INSTRUMENTATION SYSTEM (H00)

Coincident with the completion of the construction and installation of Project surface equipment, an instrumentation system was installed at the Project to record and monitor Project functions. The principal variables being measured are temperature, flow rates, and pressures. Appendix "E" is a description of the Project data collection and reduction system prepared by Williams Brothers Engineering Company, the firm who designed the Project instrumentation system.

The development of the data reporting format as presented in the Williams Brothers report has evolved over the initial five months of Project operation, and is subject to Modification as dictated by the needs of the Project.

Three areas of the instrumentation system, steam measurement, gas flow measurement, and produced fluid measurement have proved during the first five months of operation to require the most attention and maintenance. The complexities of the instrumentation system coupled with the maintenance and calibration of the system necessitated the addition of a full time technician to be responsible for calibration, maintenance and repair. The overall process of data collection has been substantially enhanced by this addition.

PROJECT DESIGN & CONSTRUCTION (I00)

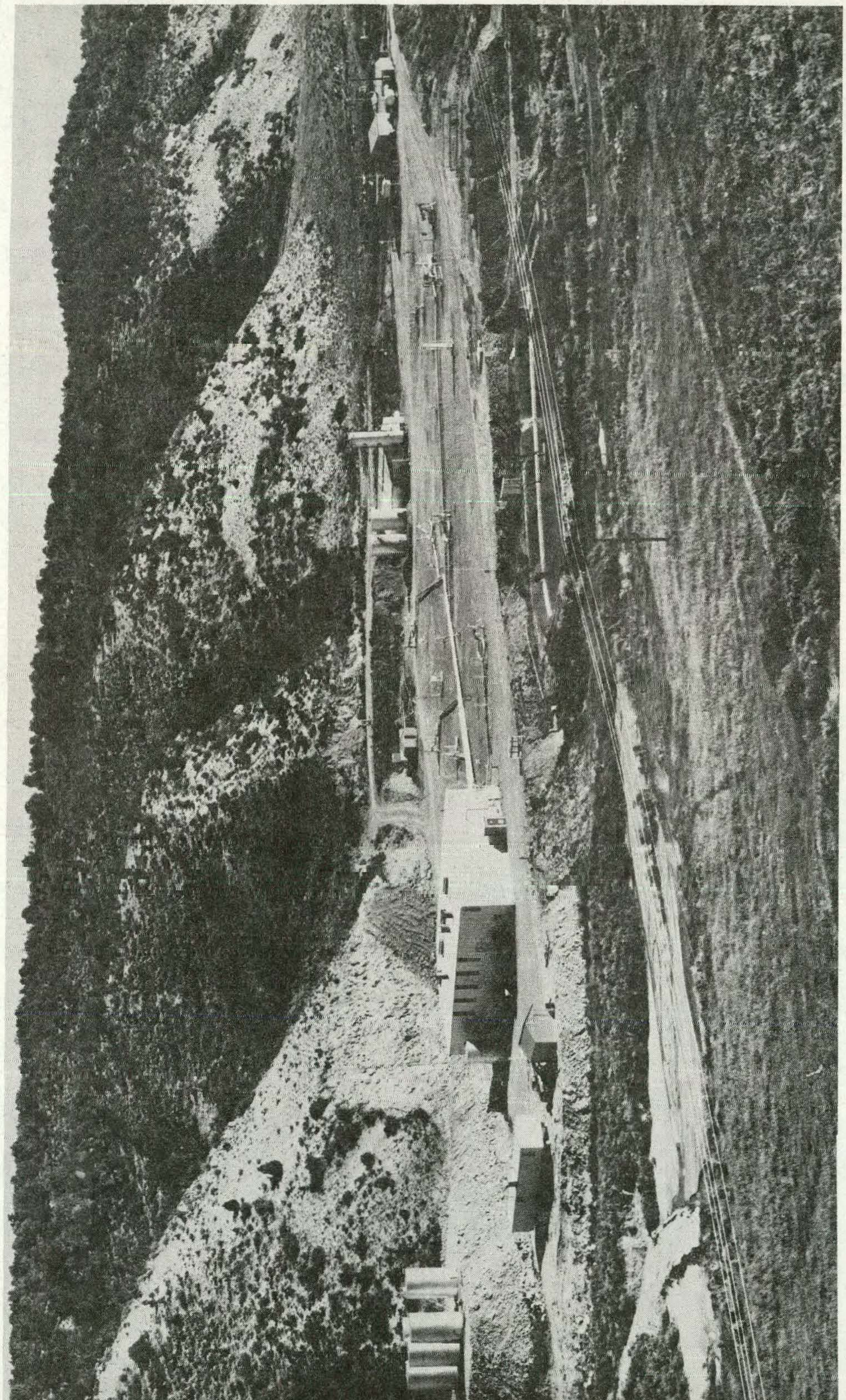
All construction was completed at the Project site in early June, 1979. Subsequent operations at the Project have occasioned minor modifications to installed equipment, however, all major elements are installed as shown on the "as built" drawings of the Project included as Appendix "F" to this report. Figures No. 9-15 are photographs of the Project site.

PROJECT OPERATIONS (J00)

By June 1, 1979, Project construction was complete and preparations were underway to commence Project operations. On June 11, 1979, Steam Generators No. 1 and No. 2 were fired for the first time and the injection of hot water was initiated. From June 11, 1979, through July 31, the injection equipment was operated and limited amounts of saturated and superheated steam were injected into the Project injection wells. The activities for the period June 1, 1979 - August 31, 1979 are summarized in Table VI. No injection of consequence was accomplished during this period due to a variety of mechanical problems affecting the superheater, instrumentation and injection wellheads. Data collection for this period is in permanent storage, but the injection data for the Project will be accumulated beginning with September 18, 1979, the first day on which continuous steam injection began.

Continuous steam injection at the Project site began on September 18, 1979, and has continued through February 29, 1980 with exception of three days in November when tubes of the steam generators were being acidized to remove observed and/or possible scale buildup. Tables VII, VIII, IX, X, XI, and XII summarize the daily operating status of the Project for this initial injection period.

Figure 9



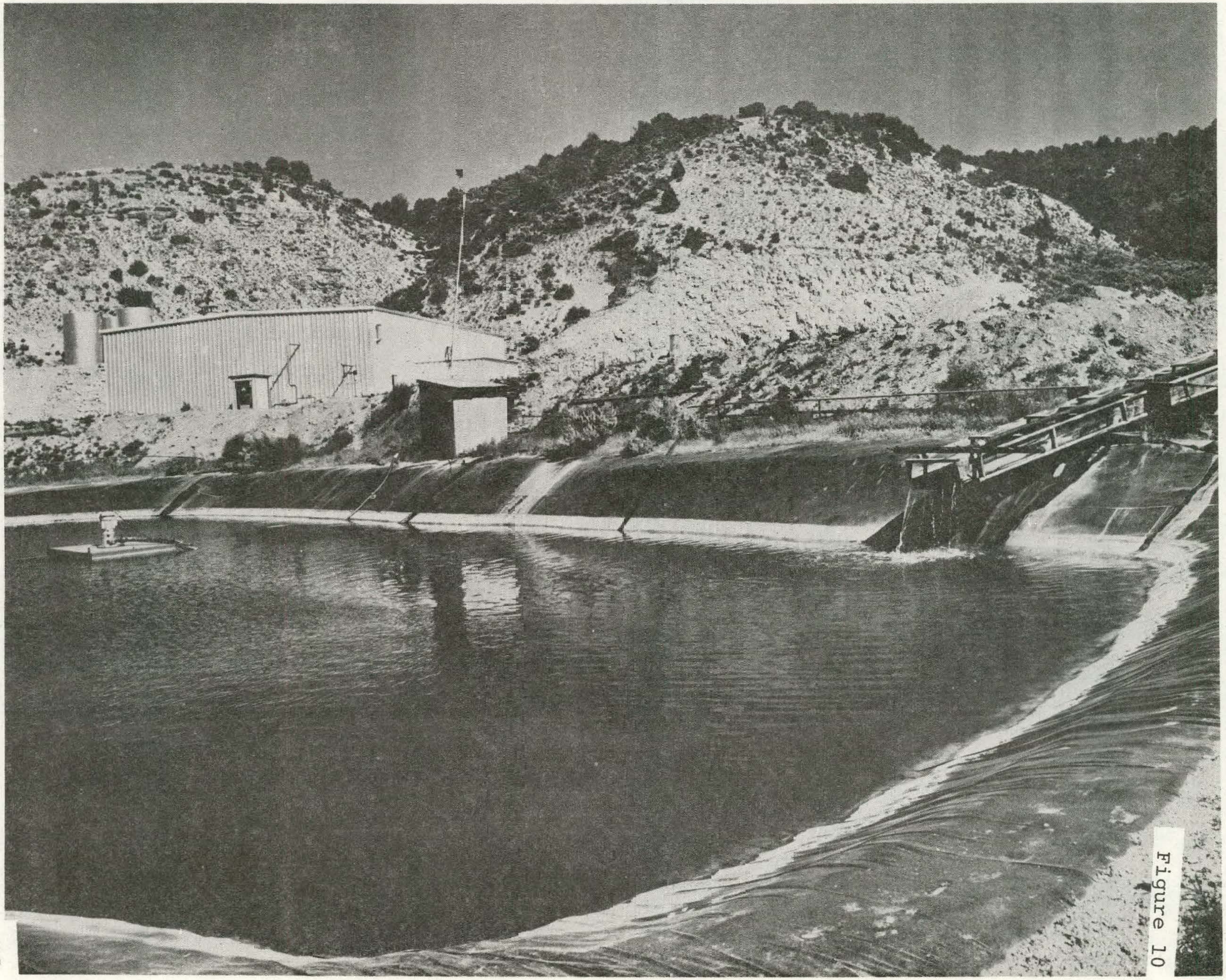


Figure 10

Figure 11

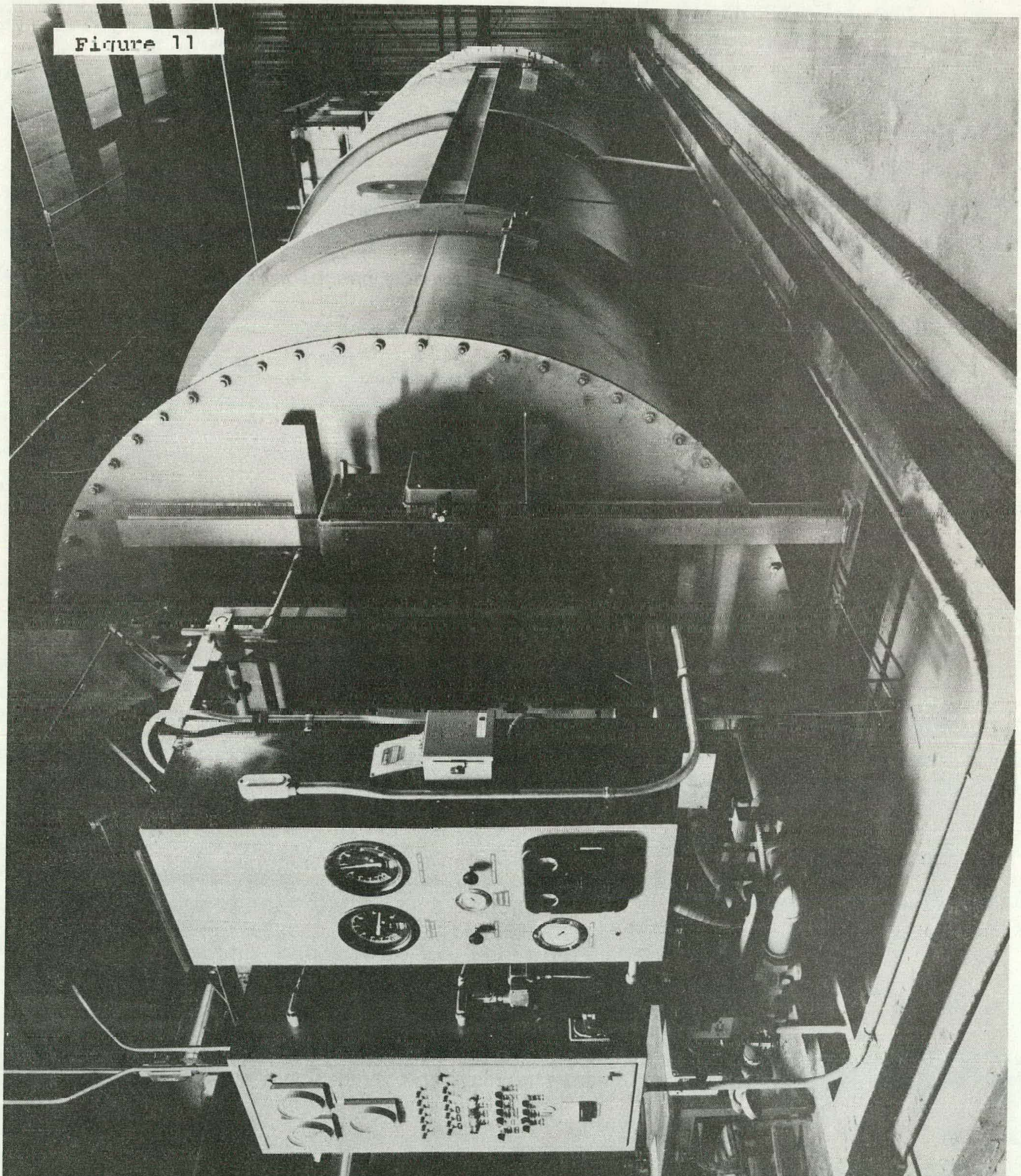


Figure 12

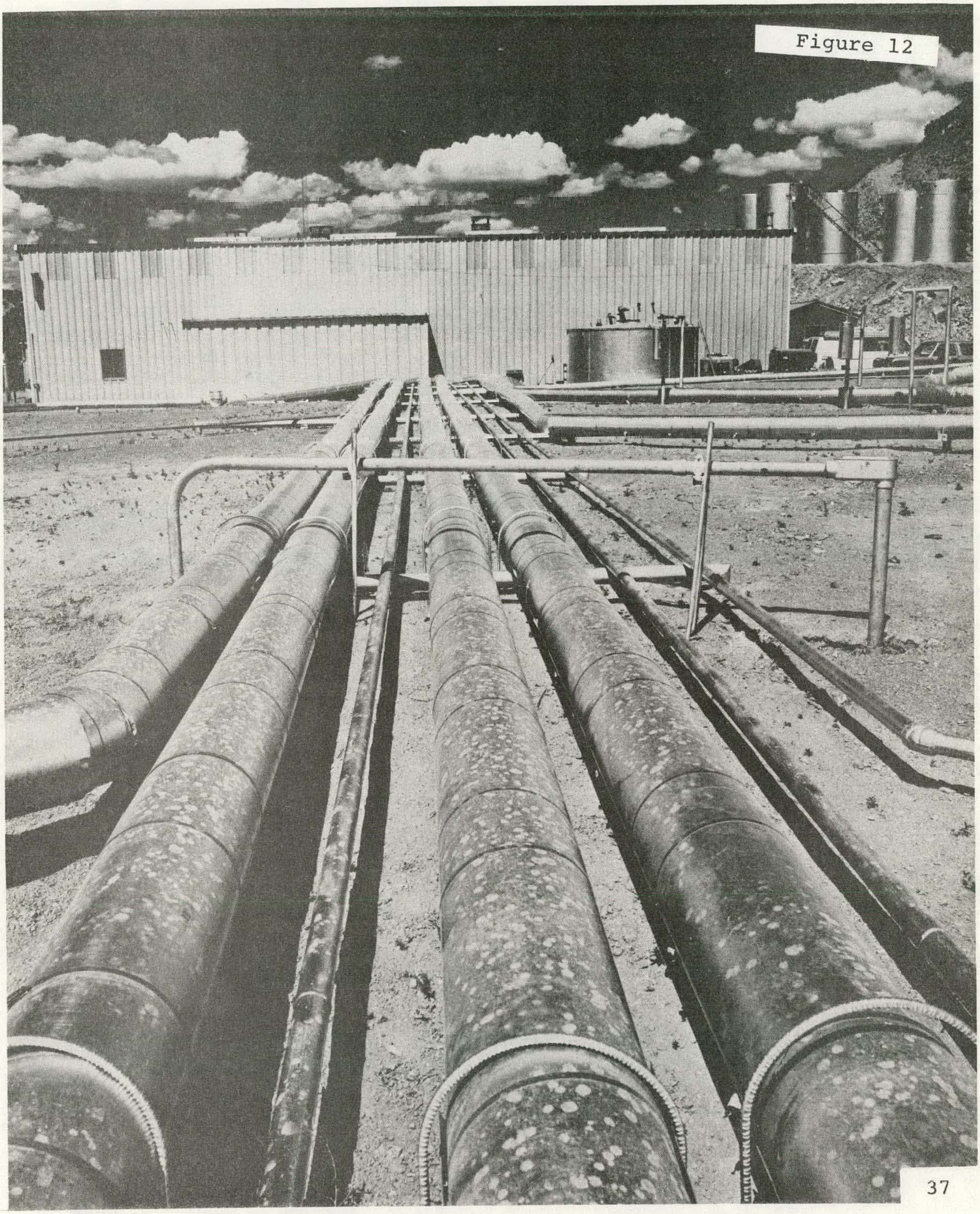
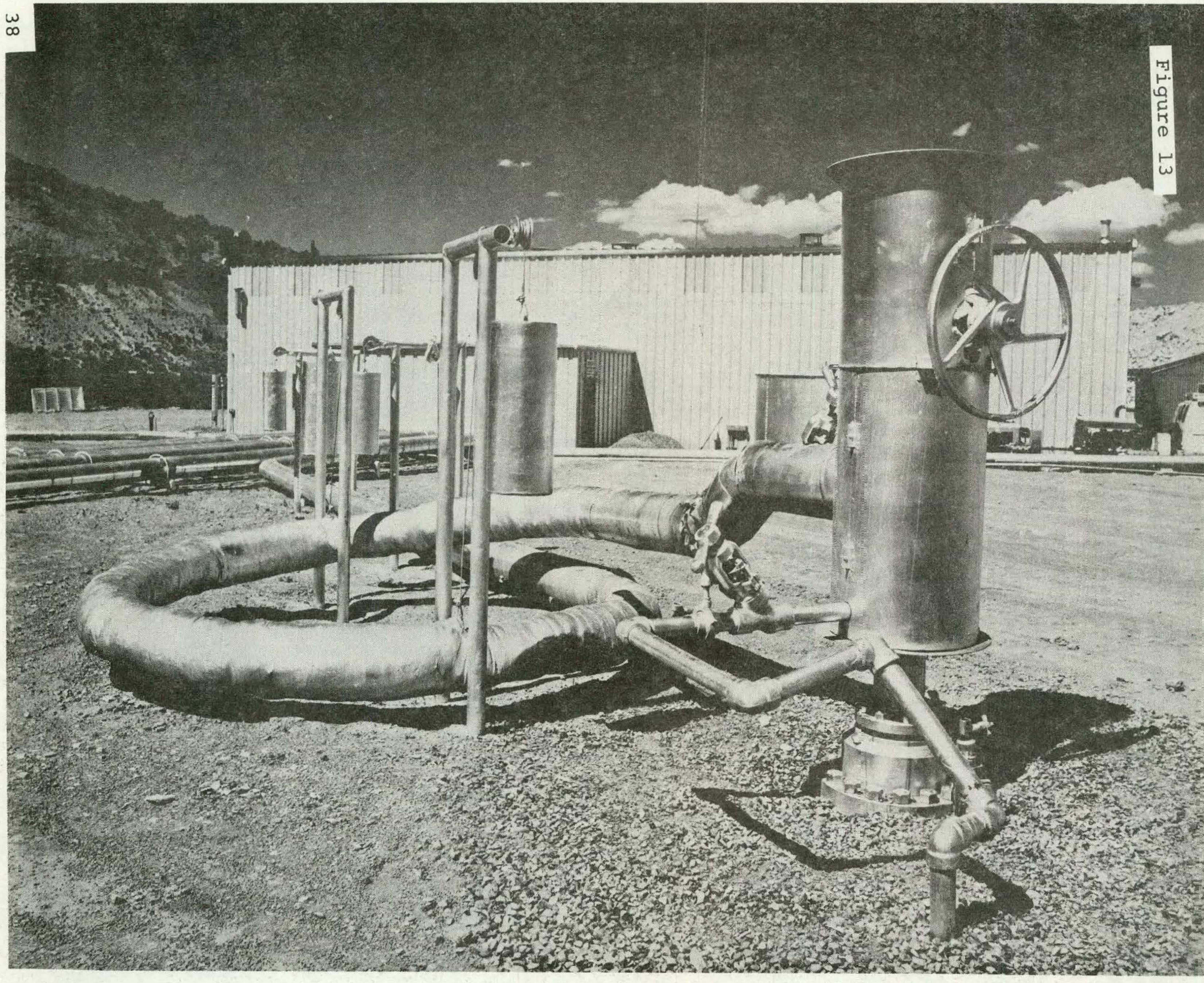


Figure 13



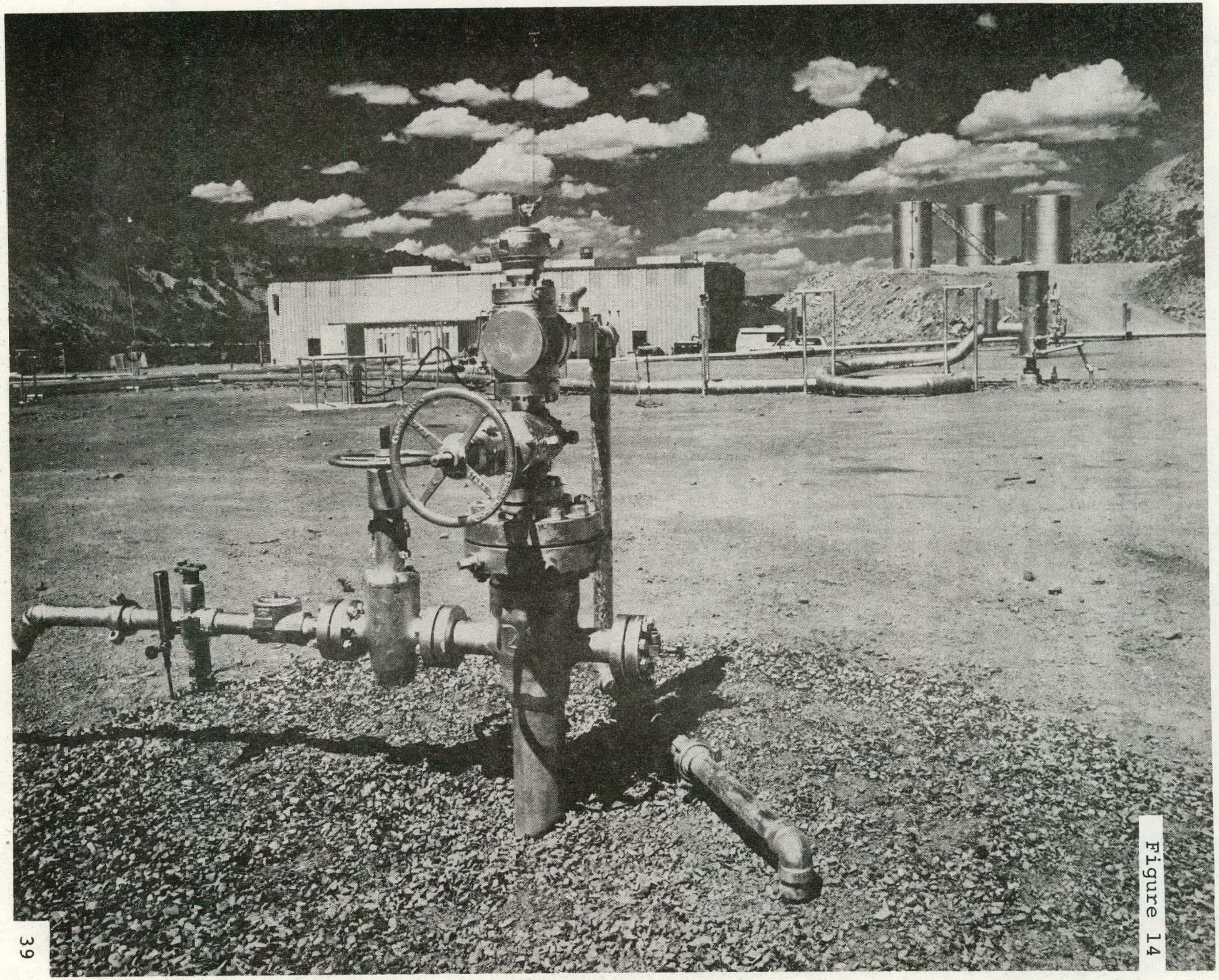


Figure 14

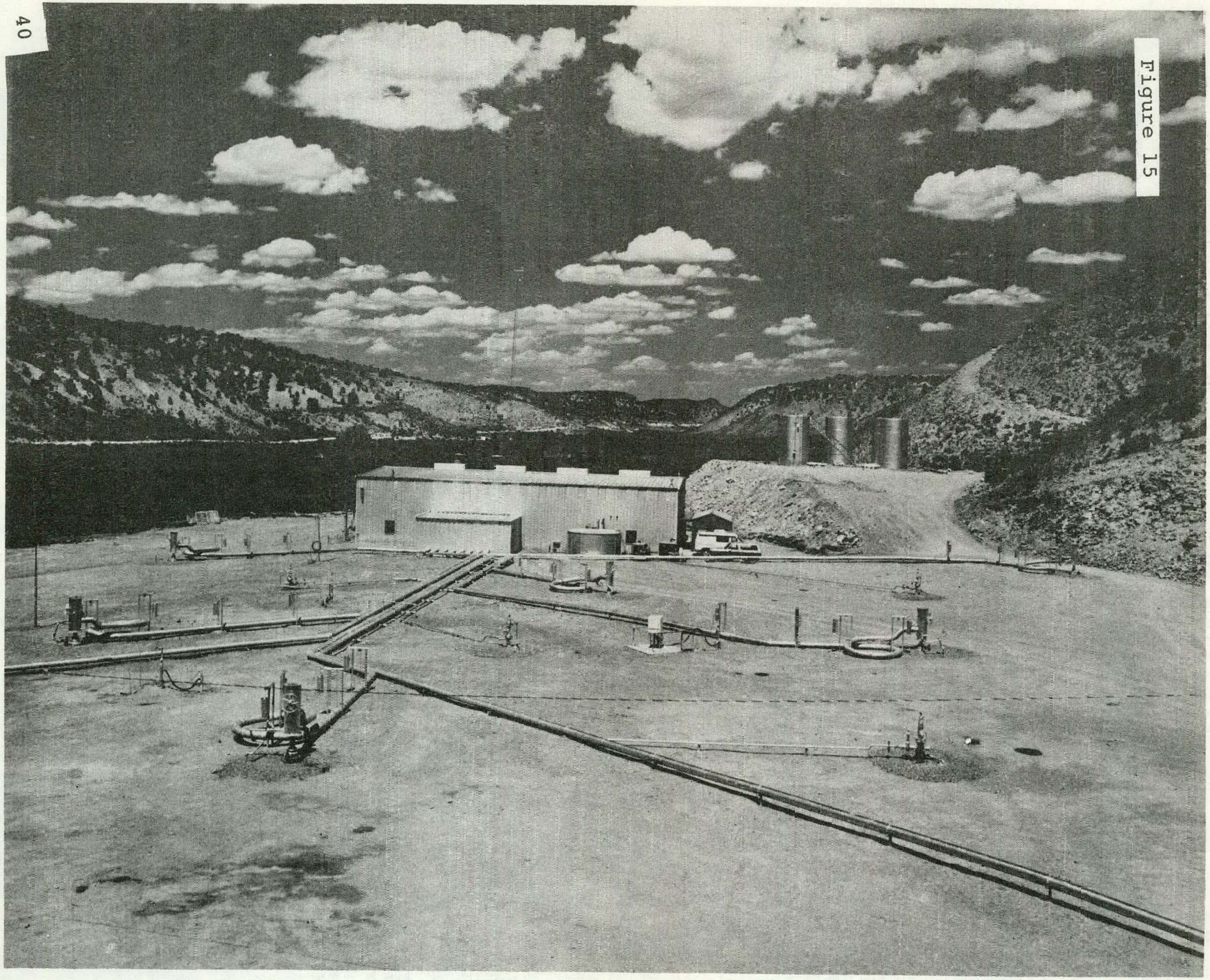


Figure 15

BX IN SITU OIL SHALE PROJECT
OPERATIONS SUMMARY
JUNE, 1979
TABLE VI

DATE	ACTIVITY
6-1-79 to 6-3-79	Preparing for injection startup.
6-4-79 to 6-10-79	Injection tests performed by VTN. Injection into BX-16 and BX-20. Rates varied between 50 and 100 GPM.
6-11-79	Fired Steam Generators No. 1 and No. 2 began injection of hot water and steam all injection wells. Plan to equal injection all wells at capacity of both Steam Generators gradually working up to 300°F. and required pressure.
6-12-79	Injection, BX-19 to test separator all other wells to free water knockout.
6-13-79	Injection.
6-14-79	Injection, wellheads beginning to expand, added corrosion inhibitor to all Production wells. Placed corrosion coupons in outlets of all five production wells.
6-15-79	Injection.
6-16-79	Injection, Steam Generator No. 2 down @ 0330 w/by pass control valve problem.
6-17-79	Injection.
6-18-79	Injection, first attempt to use gaslift recycle gas as fuel.
6-19-79	Injection, good use of gaslift gas as fuel. Purchased gas dropped from 800 MCF/day to 340 MCF/day.
6-20-79	Injection, preparing to run temperature logs in injection wells. Will maintain injection @ 300°F. during tests.
6-21-79	Injection.
6-22-79	Injection.

BX IN SITU OIL SHALE PROJECT
OPERATIONS SUMMARY
JUNE, 1979
Table VI

DATE	ACTIVITY
6-23-79	Injection.
6-24-79 to 6-28-79	Shut down injection @ 1800.
6-29-79 to 6-30-79	No injection, preparing to acidize old Steam Generator to clean out scale.

Table VII
BX In Situ Oil Shale Project
Operation Summary
September 1979

DATE	ACTIVITY
9-1-79 to 9-17-79	Calibrating instruments; install insulation on bunk house and production building; pump test BX-26 (upper aquifer monitoring well); installed production survelliance monitors; received wellhead valves back from Rockwell and reinstalled.
9-18-79	All wellhead valves back on, injection resumed at 1330 with start up of steam generator No.2 steam to wells at 1430. Steam generator No.2 on 1430 to 2400 pressure and temperature coming up.
9-19-79	Steam injection: #2 generator on 24 hrs. 580^{o}F., 1400 PSIG. Power outage problems caused shutdown of steam generator.
9-20-79	Steam injection: #2 generator on 24 hrs. 580^{o}F., 1400 PSIG.
9-21-79	Steam injection: #2 generator on 24 hrs. #1 generator on 7 hrs. (Turned on at 1730). All wells taking steam #3 and #5 (BX-30 and BX-32) not taking steam as well as other wells.
9-22-79	Steam injection: #1 and #2 generators 24 hrs; repaired minor leaks in well head valves #5 and #6. Received and installed new thermowell for super heater. Tested flow through super heater without firing.
9-23-79	Steam injection: #1 and #2 generators on 19½ hrs. and 21¼ hrs. respectively; super heater on at low fire 2 hrs. Temperature 650^{o}F.
9-24-79	Steam injection: #1 and #2 generators on 24 hrs. Super heater down on low flow condition part of day. Total hrs. on 14½. Wells taking steam at 1450 PSIG.
9-25-79	Steam injection: #1 and #2 generators and super heater on 24 hrs. Coming up slowly in temperature 680^{o}F., 1460 PSIG. Working on flow meter calibration gas and steam.
9-26-79	Steam injection: #1 and #2 generators and super heater on 24 hrs. 704^{o}F., 1450 PSIG. Conducted press tour of Project. Power outage at 1715 and at 2130 took all units down for short period. Injection well No.3 (BX-30) not taking steam.

Table VII
BX In Situ Oil Shale Project
Operations Summary
September 1979

DATE	ACTIVITY
9-27-79	Steam injection: #1 and #2 generators and super heater on 24 hrs. 680°F., 1480 PSIG.
9-28-79	Steam injection: #1 and #2 generators and super heater on 24 hrs. 720°F., 1460 PSIG. Minor leak in sensing.
9-29-79	Steam injection: #1 and #2 generators and super heater on 24 hrs. 994°F., 1470 PSIG. Super heater down at 1600 with faulty relay and flame guard. Replaced both.
9-30-79	Steam injection: #1 and #2 generators on 24 hrs. Super heater on 9½ hrs. Super heater down to repair leak in sensing line.

NOTE: Times that generators and super heater are on include short duration shutdowns that may have occurred during a given day. Temperature and pressure noted are the temperature and pressure observed at 2400 on the day being commented on.

Table VIII
Bx In Situ Oil Shale Project
Operations Summary
October 1979

DATE	ACTIVITY
10-1-79	Steam Injection: #1 & #2 generators 24 hrs. 580°F. @ 1440 PSIG, 2477 BBL injected. 765 Prod. BX 20 on test, 74 BBL produced.
10-2-79	Steam Injection: #1 & #2 generators on 24 hrs. 565°F. @ 1450 PSIG, 2388 BBL injected, 765 BBL produced. BX-14 on test-108 BBL. prod. Blew BX-30 (injected well #3) down to pit to improve injectivity, gathered production and pipeline gas samples.
10-3-79	Steam Injection: #1 & #2 generators on 24 hrs. 560°F. @ 1400 PSIG, 2241 BBL injected, 720 BBL Prod, BX-14 on test-63 BBL produced.
10-4-79	Steam Injection: #1 generator on 15 hrs. #2 generator on 24 hrs., 2425 BBLs injected, 760 BBL prod., BX-14 on test 121 BBL produced.
10-5-79	Steam Injection: #1 and #2 generator on 24 hrs., 2461 BBLs injected, 613 BBLs produced, BX-14 on test, 134 BBL prod.
10-6-79	Steam Injection: #1 & #2 generator on 24 hrs.
10-7-79	Steam Injection: #1 & #2 generator on approx. 15 hrs. due to power outage, 2535 BBLs injected, 791 BBLs produced. BX-14 on test 130 BBL produced.
10-8-79	Steam Injection: #1 & #2 generator on 24 hrs., power failure @ 2301 last data on disk.
10-9-79	Steam Injection: #1 & #2 generator on 24 hrs. 2461 BBL injected, 580°F. @ 1420 PSIG, 774 BBL. prod., BX-21 on test-105 BBL produced.
10-10-79	Steam injection: #1 & #2 generator on 24 hrs. 2278 BBLs injected @ 580°F. 1420 PSIG, 698 BBL prod., BX-21 on test-105 BBL produced.
10-11-79	Steam Injection: #1 & #2 generator on 24 hrs. 2278 BBLs Inj., @ 580°F. 1400 PSIG, 635 BBL produced, BX-21 on test 87 BBL produced.

DATE	ACTIVITY
10-12-79	Steam Injection: #1 & #2 generator 24 hrs. 2285 BBL injected at 580°F. 1500 PSIG, 771 BBL produced, BX-21 on test-102 BBL produced.
10-13-79	Steam Injection: #1 & #2 generator on 24 hrs. 2204 BBL injected, @ 570°F. 1450 PSIG, 748 BBLs produced, BX-21 on test-82 BBL prod. Problems with injection of waste water in BX#2 and #3. Precipitation of material in waste water tank causes disposal pump to loose suction.
10-15-79	Steam Injection: Generator #1 & #2 on 24 hrs. 2278 BBLs injected @ 565°F., 1450 PSIG. 730 BBLs produced.
10-16-79	Steam Injection: Generator #1 & #2 on 14 hrs. 1874 BBL injected @ 565°F. 1450 PSIG, 671 BBLs produced. Back flowed BX-#30 injection well (injection well #3) to help injectivity. Small amount of oil produced in back flowing sample taken.
10-17-79	Steam Injection: Generator #1 & #2 on 24 hrs. Superheater on 24 hrs. 1800 BBL injected @ 680°F. 1350 PSIG. First day of month in superheat. Produced 374 BBL BX-20 on test 71 BBL. Produced personate BX-20 to increase production. Clean out BX-30 with coiled tubing unit to increase injectivity. Also perforate BX-30.
10-18-79	Steam Injection: Generator #1, #2 and superheater on 24 hrs. 1652 BBL injected @ 1000°F. 1360 PSIG, 761 BBLs produced, BX-20 on test-107 BBL produced.
10-19-79	Steam Injection: Generator #1 & #2 on 24 hrs. and 23 hrs. Superheater on 21 hrs. 1580 BBL injected @ 950°F. 1350 PSIG, 761 BBLs produced, BX-20 on test 102 BBL produced.
10-20-79	Steam Injection: Generator #1 & #2 on 23 and 24 hrs. respectively and superheater on 19 hrs., 1690 BBLs injected @ 950°F. @ 1403 PSIG, 767 BBL produced, BX-20 on test-98 BBL produced. Problems with steam generator #2 and superheater with high pressure.
10-21-79	Steam Injection: Generator #1 on 24 hrs. #2 on 22 hrs. Superheater down because of leaks. 1910 BBL injected at 570°F. 1350 PSIG, power outage @ 2145 put #2 generator down.
10-22-79	Steam Injection: Generator #1 on 24 hrs. #2 on approx. 10 hrs. Electrical outages causing shutdown and restart problems. Data Recovery bad due to electrical outages. Acidize BX-20. 1580 BBL injected.

DATE	ACTIVITY
10-23-79	Steam Injection: Generator #1 & #2 on 24 hrs., 1580 BBLs injected @ 590^{O}F. 1480 PSIG, 489 BBLs produced, BX-20 on test-147 BBL produced.
10-24-79	Steam Injection: Generator #1 on 24 hrs. Generator #2 on 20 hrs., 1690 BBLs injected @ 580^{O}F. 1440 PSIG, 647 BBL produced BX-20 on test-192 BBL produced.
10-25-79	Steam Injection: Generator #1 on 24 hrs. #2 on 15 hrs. Numerous power outages made it impossible to keep #2 generator running 829 BBL injected @ 580^{O}F. 1380 PSIG, 845 BBL produced BX-20 on test-211 BBL produced.
10-26-79	Steam Injection: Generator #1 on 18 hrs. #2 on 7 hrs. 1680 BBL injected @ 580^{O}F., 1430 PSIG, 860 BBL produced BX-20 on test-207 BBL produced. Continued power problems (12 dips during day).
10-27-79	Steam Injection: Generator #2 on 24 hrs. 1296 BBLs injected @ 570^{O}F., 1340 PSIG, 868 BBL produced BX-20 on test 202 BBL produced, generator #2 on only because can not keep both generators running with power problems.
10-28-79	Steam Injection: Generator #2 on 24 hrs. 1440 BBLs injected @ 580^{O}F. 1440 PSIG, 788 BBLs produced BX-20 on test 209 BBL produced.
10-29-79	Steam Injection: Generator #2 on 24 hrs. 1503 BBLs injected @ 585^{O}F. 1465 PSIG, 907 BBLs produced BX-20 on test 195 BBL produced.
10-30-79	Steam Injection: Generator #2 on 24 hrs. 1508 BBLs injected @ 575^{O}F. 1400 PSIG, 741 BBLs produced BX-20 and 14 on test 97 BBL produced.
10-31-79	Steam Injection: Generator #2 on 24 hrs. 1457 BBLs injected @ 570^{O}F., 1400 PSIG, 707 BBLs produced, BX-14 on test -70 BBL produced. Resolved source of power outages to be fan metor at multi minerals plant.

NOTE: Times that generators and superheater are on include short duration shutdowns that may have occured during a given day. Temperature and pressure noted are the temp. and pressure observed at 2400 on the day being commented on. Injectivity amounts are based on boiler feed water rate and assumed steam quality of 80%.

Table IX
BX In Situ Oil Shale Project
Operations Summary
November 1979

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-heater	Barrels Injected	Temp. of	Pressure PSIG	Barrels Prod.	Test Well Prod.
11/1/79	Injection, #2 gen. only, problems w/ freezing in production wells BX-30 not taking steam.		24 hrs.		1440	503	1340	599	
11/2/79	Injection, #2 gen. only. Found leaks in convection section. No.2 gen @ 2300 shut unit down. No.1 gen. on line BX-30 not taking steam.		23 hrs.		1076	493	1281	511	
11/3/79	Injection, #1 gen. only, began work to isolate tube problems in gen. No.2. BX-30 not taking steam.	23 hrs.			1231	386	1190	781	
11/4/79	Injection, #1 gen. only, leaks isolated in #2 gen. power outage, same apparent cause as in late October. BX-30 not taking steam BX-23 shut in w/leak at control valve.	24 hrs.			1199	503	1341	790	
11/5/79	Injection #1 gen. only, BX-30 not taking steam, BX-23 still down. Only injection well #1,4,5,8 indicate steam flow by well heat thermocouples.	24 hrs.			1204	497	1330	737	
11/6/79	Injection #1 gen. only, injection wells 1, 4,5,8 taking most of steam.	24 hrs.			1233	496	1302	694	3/64
11/7/79	Injection #1 gen. only, working on water treatment system & beginning to remove damaged tubes from steam gen. No.2. Inj. wells 1,4,5,& 8 taking most of steam.	24 hrs.			1193	487	1272	733	3/89
11/8/79	Injection #1 Gen. only, pulled 5 bad tubes from #2 gen. Inj. wells 1,4,5, & 8 taking most of steam.	24 hrs.			921.61	493	1189	673	4/117

Table IX
BX In Situ Oil Shale Project
Operations Summary
November 1979

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-heater	Barrels Injected	Temp. oF	Pressure PSIG	Barrels Prod.	Test Well Prod.
11/9/79	Injection, Steam gen. No.1 only.	24 hrs.						644	4/103
11/10/79	Injection, gen. No.1 only, inj. wells No.1,4,5, & 8 taking most of steam.	24 hrs.			911	491	899	536	0/69
11/11/79	Injection, gen. No.1 only, work on water treatment equip. inj. wells 1,4,5, & 8 taking most of steam.	24 hrs.			747	503	819	307	0/48
11/12/79	Injection, gen. No.1 only. Inj. wells No. 1,4,5,& 8 taking most of steam.	24 hrs.			834	506	947	91*	1/?
11/13/79	Injection, gen. No.1 only. Welders on site to repair gen. No.2.	24 hrs.			830	506	1005	24*	
11/14/79	Injection, gen. No.1 only, pressure checked No.2 gen. one more leaking tube. Tube repaired & welders finished @ 2251. Inj. wells No. 1, 4,5,& 8 taking most of steam.	24 hrs.			733		983	48	0/52
11/15/79	Injection, gen. No.1 only, pressure checked gen. No.2 @ 1400 PSIG for 30 min. No leaks developed. Injection wells No.1,4,5,& 8 taking most of steam.	24 hrs.			810	506	1037	110*	0/52
11/16/79	Gen. No. 1 injecting only. Acidizing gen. & superheater to remove scale. Acidized gen. in series and superheater separately.	8.5 hrs.			278	506	1044	58*	0/40
11/17/79	No Injection. Acidizing steam gen. & superheaters. Finished w/gen. & injected spent acid into disposal wells. Acid opened leaks in disposal tank. Disposal tank replaced.							58	

Table IX
BX In Situ Oil Shale Project
Operations Summary
November 1979

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-heater	Barrels Injected	Temp. of	Pressure PSIG	Barrels Prod.	Test Well Prod.
11/18/79	No injection, revamped piping on prod. well chokes & installed box heating. on same. Completed repairs & acidizing.							40	1/0
11/19/79	Completed Hydrotest on all units. Tested to 2450# held for 30 min. Started steam gen. no.1 @ 1900.	5 hrs.						0	1/0
11/20/79	Injection, steam generator No.1 only. Gradually bringing temperature and pressure.	24 hrs.			983	320	597	24	1/19
11/21/79	Injection, steam generator No.1.	24 hrs.			1280	464	912	0	---*
11/22/79	Injection, steam gen. No.1 finished reassembly of insulation on steam gen. No.1.	24 hrs.			1242	461	1006	0	---*
11/23/79	Injection, steam gen. No.1, mixing hot water for frac job w/ steam gen. #2.	24 hrs.			1204	452	1051	0	---*
11/24/79	Injection, steam gen. No.1 fraced all prod. and injection well No.3 (BX-30) with same treatment. Frac. on prod. wells went well BX-30 sanded out. Using steam gen. No.2 to heat frac. water.	24 hrs.			1249	452	1070	0	---*
11/25/79	Injection, steam gen. No.1.	24 hrs.			1255	452	1091	0	---*
11/26/79	Injection, steam gen. No.1.	24 hrs.			1394	452	1118	0	---*
11/27/79	Injection, steam gen. No.1, bringing prod. wells back on line. Thawing BX-30.	20 hrs.			1082	477	1150	55 (four hrs. prod.)	1/44
11/28/79	Injection, Steam gen. No.1.	22 hrs.			1157	455	908	817	1/817
11/29/79	Inj. steam gen. No.1, No data logger data for day.*Barrels inj. from totalizers	22 hrs.	1 hr.		833*	459	884	345	1/342
11/30/79	Inj. steam gen. No.1&2, power problem caused data logger shut down.	22 hrs.	10 hrs.		1085	459	884		4/-

Table IX
BX In Situ Oil Shale Project
Operations Summary
November 1979

NOTE: 1) Temperatures are average wellheat temperature of those wells taking steam, and pressures are average injection pressures of those wells taking steam as measured downstream of the control valve for each well. Injection Volumes have been calculated based upon injection meter readings, Steam Quality and Feed Water rates for the Steam Generator or Generators being operated.

2) Production tubing was pulled from the Production wells to accommodate the fracturing treatment, and this accounts for lack of Production for November 19th through 26th.

Table X
BX In Situ Oil Shale Project
Operations Summary
December 1979

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-heater	Barrels Injected	Temp. of	Pressure PSIG	Barrels Prod.	Test Well Prod.
12/1/79	Injection, Gen. No.1 & No.2, Gen. No.1 inj. steam, No.2 on low fire & coming up flowing to pond for day.	24 hrs.	24 hrs.		1256	471	990	568	
12/2/79	Injection, Gen. No.1 and Gen. No.2 (part of time) No significant contribution from No.2 *Data logger missing (check).	24 hrs.	12 hrs.		580*			476	
12/3/79	Injection, Gen. No.1 & Gen. No.2 (part of time) Heating up superheater (No fire).	24 hrs.	19 hrs.		1852	440	1075	870	?/18
12/4/79	Injection, Gen. No.1 & No.2 on, cont. problems w/gas lift system.	24 hrs.	24 hrs.		2219	464	1209	744	3/106
12/5/79	Injection, Gen. No.1 & Gen. No.2 (part time)	24 hrs.	16 hrs.		1744	492	1328	913	1/214
12/6/79	Injection, Gen. No.1 & superheater on short time	24 hrs.		5½hrs.	1291	492	1232	321	4/151
12/7/79	Injection, Gen. No.1 & superheater. Problems w/shut downs of Gen. No.1 due to hydrates in gas.	24 hrs.		24 hrs.	1125	554	1322	328	4/328
12/8/79	Injection, Gen. No.1 and superheater.	24 hrs.		24 hrs.	1101	638	1354	271	4/271
12/9/79	Injection, Gen. No.1 & switched to Gen. No.2 during day, plus superheater. Continued production problems.	14 hrs.	10 hrs.	24 hrs.	1349			18	4/18
12/10/79	Injection, Gen. No.2 & superheater. Developed crack on tee at superheater outlet. Shut superheater down @ 1820 to repair. Working on production.		24 hrs.	18 hrs.	1089	590	1364	780	4/205
12/11/79	Injection, generator No.2		24 hrs.		1099	493	1266	885	4/214

Table X
BX In Situ Oil Shale Project
Operations Summary
December 1979

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-Heater	Barrels Injected	Temp. °F.	Pressure PSIG	Barrels Prod.	Test Well Prod.
12/12/79	Injection, Gen. No.2, No data logger data from 05:05 on.		24 hrs.		1133	497	1355	787	4/329
12/13/79	Injection, Gen. No.1 (part of time) and No.2. Found leak in convective section Gen. No.1. Shut down to locate & repair leak.	3.5 hrs.	24 hrs.		1117	501	1355	1019	4/291
12/14/79	Injection, Gen, No.2 located leaks in steam Gen. No.1 in 180° tube turns in convective section.		24 hrs.		1107	493	1310	625	4/270
12/15/79	Injection, Gen. No.2.		24 hrs.		1194	516	1235	773	4/262
12/16/79	Injection, Gen. No.2, prod. problems cont.		24 hrs.		1193	523	1222	570	0/132
12/17/79	Injection, Gen. No.2.		24 hrs.		1259	523	1239	228	0/125
12/18/79	Injection, Gen. No.2, switching prod. chokes to inside of building.		24 hrs.		1240	488	1296	265	0/36
✓12/19/79	Injection, Gen. No.2 chokes moved to steam gen. building. Gas lift back on @ 21:95.		24 hrs.		1174	499	1321	86	0/0
12/20/79	Injection, Gen. No.2.		24 hrs.		1103	503	1126	33	0/33
12/21/79	Injection, Steam Gen. No.2 only. Working on repairing superheater leaks. 3 more leaks found.		24 hrs.		1082	496	1173	83*	0/83
12/22/79	Injection, Steam Gen. No.2 only. Working on production wells. Power dip @ 15:50.		24 hrs.		1013	472	1079	164*	0/164
12/23/79	Injection, Steam Gen. No.2 only. Working on Production wells and repairing leaks on superheater & No.1 Generator. Preparing for Hydrotest of Steam Gen. No.1 & Superheater.		17 hrs.		564	479	1047	61	0/56

Table X
BX In Situ Oil Shale Project
Operations Summary
December 1979

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-Heater	Barrels Injected	Temp. °F.	Pressure PSIG	Barrels Prod.	Test Well Prod.
12/24/79	Injection--Steam Gen. No.2 only. Working on Production wells and instr. calibration.		24 hrs.		1020	461	1040	480	0/211
12/25/79	Injection-Steam Gen. No.2 only. Problems with instrument air.		24 hrs.		1001	448	1088	412	0/0
12/26/79	Injection-Steam Gen. No.2 only. Resolved problems w/instrument air supply. Work on instrument calibration.		24 hrs.		1086	492	1145	363	0/0
12/27/79	Injection-Steam Gen. No.2. Calibrating instruments. Took environmental samples.		24 hrs.		1044	493	1150	590	1/332
12/28/79	Injection-Steam Gen. No.2. Working w/prod. wells. Production volume coming up.		24 hrs.		1070	482	1166	852	1/570
12/29/79	Injection-Steam Gen. No. 2. Working w/ prod. wells.		24 hrs.		1192	475	1201	1320	1/413
12/30/79	Injection-Steam Gen. No. 2. Working w/prod. wells and calibrating inst.		24 hrs.		1387	494	1217	912	1/302
12/31/79	Injection-Steam Gen. No. 2. Production improving.		24 hrs.		1416	495	1262	1367	1&4/409

*Average injection temperature is measured at the injection wellheads with thermocouples attached to the outside of the injection flow line, hence the actual flowing temperature will be slightly higher than that which is recorded.

**Average injection pressure is measured downstream of the control valve for each injection well and is an average of all wells. Refer to the Data Summary Appendix "B" for data on individual well performance.

Table XI

BX In Situ Oil Shale Project
Operations Summary
JANUARY 1980

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-Heater	Barrels Injected	Temperature °F.	Pressure PSIG	Barrels Produced	Test Well/ Injection
1-1-80	Injection-Steam Gen. No.2. Pinhole leaks injection well #5. Working on production wells.		24 hrs.		1383	493	1267	1090	4/277
1-2-80	Injection-Steam Gen. No.2. Working with production wells.		24 hrs.		1370	516	1273	815	4/200
1-3-80	Injection-Steam Gen. No.2. Completed repairs to Steam Generator No.1 working on Production wells.		24 hrs.		1381	517	1251	1272	4/222
1-4-80	Injection-Steam Gen. No.2. Hydrotested Steam Gen. No.1 and superheater.		24 hrs.		1408	492	1119	1125	3/252
1-5-80	Injection-Steam Generator No.2.		22 hrs.		1414	494	1125	1127	3/320
1-6-80	Injection-Steam Gen. No.2. New leak developed in superheater when flowing steam through to preheat. Took superheater out of line. Arranging repair.		24 hrs.		1269	466	1145	811	3/132
1-7-80	Injection-Steam Gen. No. 2. Repairing valve on injection well #8.		24 hrs.		1183	482	1334	690	3/143
1-8-80	Injection-Steam Gen. No. 2. Repairing valve on injection well #8. Found new leak in superheater.		24 hrs.		1183	489	1346	956	3/279
1-9-80	Injection-Steam Gen. No. 2. Repairing valve on injection well #8. Evaluating superheater problems.		24 hrs.		1183	498	1369	1164	3/273
1-10-80	Injection-Steam Gen. No. 2. Repairing valve on injection well #8. Took VTN water samples. Not able to get samples BX-36. Pumped well down.		24 hrs.		1207	496	1384	1186	3/260

Tabel XI

BX In Situ Oil Shale Project
Operations Summary
JANUARY 1980

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-Heater	Barrels Injected	Temperature °F.	Pressure PSIG	Barrels Produced	Test Well/ Production
1-11-80	Injection-steam gen. No. 2 Injection well #8 still down. Universal testing on site to x-ray welds on superheater. Continued production problems BX-20 shut-in.		24 hrs.		1159	491	1363	1147	3/264
1-12-80	Injection-steam gen. No. 2, Gen. No. 1 on part of day, x-raying superheater welds.	1 hr.	24 hrs.		1187	477	1392	1119	0/258
1-13-80	Injection-steam gen. No. 1 & 2. No. 2 generator down part of day for repairs. Injection well No. 8 still down.	20 hrs.	12 hrs.		1402	473	1366	1070	0/184
1-14-80	Injection-steam gen. No. 1 & 2. Cleaned burner and burner nozzel Gen No. 2. Gen. No. 1 down to repair leak. Repacked steam valve BX-33.	18 hrs.	6 hrs.		619	464	1186	1035	0/189
1-15-80	Injection-steam gen. No. 2.	24 hrs.			1291	480	1251	948	0/104
1-16-80	Injection-steam gen. No. 2.	24 hrs.			1396	499	1276	930	0/102
1-17-80	Injection-steam gen. No. 2. Two power dips caused loss of data on disk. Salt delivered.	24 hrs.			1385	478	1251	1063	0/202
1-18-80	Injection-steam gen. No. 2. Gen. down to install blinds on superheater. X-ray work in progress on superheater. Found welds that would not pass test.	20 hrs.			1068	371	1030	886	1/342
1-19-80	Injection-steam gen. No. 2. Welder on superheater repairs.	24 hrs.			1247	488	1227	870	3/217

Table XI
BX In Situ Oil Shale Project
Operations Summary
JANUARY 1980

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-Heater	Barrels Injected	Temperature °F.	Pressure PSIG	Barrels Produced	Test Well/ Production
1-20-80	Injection-steam gen. No. 2. X-ray & weld on superheater.		24 hrs.		1369	481	1250	847	4/655
1-21-80	Injection-steam gen. No. 2 X-ray & weld on superheater. Take environmental water samples.		24 hrs.		1420	471	1272	844	0/14
1-22-80	Injection-steam gen. No. 2. X-ray & weld on superheater.		24 hrs.		1396	491	1263	842	0/11
1-23-80	Injection-steam gen. No. 2 X-ray & weld power dip. Caused loss of data on data logger.		24 hrs.		890	*No data from data logger.		834	0/11
1-24-80	Injection-steam gen. No. 2. Working on problems of power outages caused by line hits at multiminerals operation.		24 hrs.		1444	483	1224	829	0/11
1-25-80	Injection-steam gen. No. 2.		24 hrs.		1501	494	1222	860	0/26
1-26-80	Injection-steam gen. No. 2.		24 hrs.		1447	477	1240	867	0/83
1-27-80	Injection-steam gen. No. 2.		24 hrs.		1446	481	1254	807	0/11
1-28-80	Injection-steam gen. No. 2.		24 hrs.		1380	495	1252	800	0-3/102
1-29-80	Injection-steam gen. No. 2. Will bring generator No. 1 on line to maximize saturated steam injection.		24 hrs.		1390	485	1276	955	3/157
1-30-80	Injection-steam gen. No. 1 & No. 2. Power outage problems.	20½ hrs.	11 hrs.		1510	464	1267	380	4/93
1-31-80	Injection-steam gen. No. 1.	24 hrs.			907	489	1136	876	3/6

*Average injection temperature is measured at the injection wellheads with thermocouples attached to the outside of the injection flow line, hence the actual [illegible]

Table XII
BX In Situ Oil Shale Project
Operations Summary
February 1980

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-Heater	Barrels Injected	Temperature °F.	Pressure PSIG	Barrels Produced	Test Well/ Production
2-1-80	Injection-Gen No.1. Planning to bring Gen. No. 2 on line to maximize saturated steam injection.	24 hrs.			909	482	1171	832	4/193
2-2-80	Injection-Gen. No.1 & Gen. No.2 on during day Gen. No.1 down to crack in feed outer pump piping.	6 hrs.	19 hrs.		1139	465	1129	743	4/146
2-3-80	Injection-Gen. No.2. Working on repairs to Gen. No.1.		24 hrs.		1305	474	1247	732	4/128
2-4-80	Injection-Gen. No.2 & Gen. No.1.	9 hrs.	24 hrs.		1579	486	1290	799	4/216
2-5-80	Injection-Gen. No.1 & 2. Down 2 hours because of power failure. Data Loss. 0000 to 1121.	22 hrs.	22 hrs.		2078	497	1352	662	4/92
2-6-80	Injection-Gen. No.1 & 2. Pumping BX-20 w/rod pump. Not working well. Power dip at 0440.	24 hrs.	24 hrs.		1946	495	1389	727	3/235
2-7-80	Injection-Gen. No.1 & 2. Problems w/disposal pump. No.2 generator down while repairing disposal pump. VTN samples taken.	24 hrs.	1.5 hrs.		1059	489	1248	586	3/240
2-8-80	Injection-Gen. No.1 & 2. BX-20 not pumping well. Repairing disposal pump.	24 hrs.	4 hrs.		1149	475	1180	693	3/241
2-9-80	Injection-Gen. No.1 & 2. No production on BX-20.	24 hrs.	24 hrs.		2173	484	1383	849	3/249
2-10-80	Injection-Gen. No.1 & 2.	24 hrs.	24 hrs.		2020	494	1434	784	3/240
2-11-80	Injection-Gen. No.1 & 2. Problems w/No. 2 generator. BX-20 pumping fluid.	24 hrs.	17.33 hrs.		1752	487	1407	766	2/177

Table XII
BX In Situ Oil Shale Project
Operations Summary

February 1980

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-Heater	Barrels Injected	Temperature °F.	Pressure PSIG	Barrels Produced	Test Well/ Production
2-12-80	Injection Gen. No. 1 & 2.	24 hrs.	24 hrs.		1857	489	1446	785	2/40
2-13-80	Injection Gen. No. 1 & 2. Gen. No. 1 down for repair of leaking fitting. Problems continue with measurement of steam of injection well No. 3.	21 hrs.	24 hrs.		1749	507	1426	809	2/82
2-14-80	Injection Gen. No. 1 & 2.	24 hrs.	24 hrs.		1695	510	1435	787	2/8
2-15-80	Injection Gen. No. 1 & 2.	24 hrs.	24 hrs.		1686	512	1443	780	2/21
2-16-80	Injection Gen. No. 1 & 2.	24 hrs.	24 hrs.		1696	501	1446	735	2/4
2-17-80	Injection Gen. No. 1 & 2.	24 hrs.	24 hrs.		1737	492	1434	722	0/0
2-18-80	Injection Gen. No. 1 & 2. Gen. 1 down 9 hrs. to repair leaking fitting. Installed turbine meter in dispoal line. Temperature decrease points # 839,840,841?	15 hrs.	24 hrs.		1509	488	1434	719	2/0
2-19-80	Injection Gen. No. 1 & 2. Injection well #4 down 4 hrs. with leaking valve.	24 hrs.	24 hrs.		1784	492	1423	727	1/199
2-20-80	Injection Gen. No. 1 & 2. Both down on power failure for short period. Gen. down with repair to sample line.	22.75 hrs	20.75 hrs.		1473	490	1424	702	1/302
2-21-80	Injection Gen. No. 1 & 2. No. 2 Gen. down to repair leaks.	24 hrs.	8 hrs.		1235	494	1373	724	1/309
2-22-80	Injection Gen. No. 1 & 2.	24 hrs.	24 hrs.		1794	501	1445	831	4/256
2-23-80	Injection Gen. No. 1 & 2.	24 hrs.	23.5 hrs.		1703	495	1451	895	4/227
2-24-80	Injection Gen. No. 1 & 2.	24 hrs.	24 hrs.		1620	501	1452	839	0/165

Table XII
BX In Situ Oil Shale Project
Operations Summary

February 1980

DATE	ACTIVITY	Steam Gen. No. 1	Steam Gen. No. 2	Super-Heater	Barrels Injected	Temperature °F.	Pressure PSIG	Barrels Produced	Test Well/ Production
2-25-80	Injection Gen. No. 1 & No. 2. Leak found at front end of convective section Gen. 1 will watch until leak is large enough to isolate for certain.	24 hrs.	24 hrs.		1634	500	1455	908	0/145
2-26-80	Injection Gen. No. 1 and No. 2.	24 hrs.	24 hrs.		1631	497	1438	949	3/259
2-27-80	Injection Gen. No. 1 and No. 2. Power failure problems causing shut downs.	23.5 hrs.	23.5 hrs.		1640	491	1412	877	3/205
2-28-80	Injection Gen. No. 1 and No. 2. Two power failures caused shutdowns and loss of data on diskette.	21.5 hrs.	21.5 hrs.		No Data	No Data	No Data	684	1/293
2-29-80	Injection Gen. No. 1 and No. 2. Bad disk could not recover data on disk.	24 hrs.	24 hrs.		No Data	No Data	No Data	736	2/4

During the period, 235,060 barrels of water as steam were injected at an average wellhead pressure of 1199 PSIG and an average temperature of 456°F. All injection except 14 days was at saturated steam conditions for reasons noted below.

No oil was produced from production wells during the period, however, small amounts were observed and collected during flowback of Project injection wells. Evidence of progress in the process is best illustrated by the continuing heat up of the formation noted in the Project temperature observation wells. This heating process is illustrated in Figures 17, 18, 19 and 20.

Appendix "G" contains data summaries for the full period September 18, 1979 - February 29, 1980, and for the quarter December 1, 1979 - February 29, 1980.

General Project operations for the months during which steam injection has taken place are summarized below.

SEPTEMBER 1979

The operations at the BX Project for the month of September, 1979, included 17 days of maintenance, repairs, and equipment installation and 13 days of steam injection. During the thirteen days, 22,900 barrels of steam were injected at an average wellhead temperature of 541°F. and an average pressure of 1235 PSIG.

The acceptance of steam by the injection wells was variable with Injection Well No. 3 (BX-30) having the worst injection capacity, 51 barrels/day, and Injection Well No. 8 (BX-33) having the best injection capacity, 415 barrels/day.

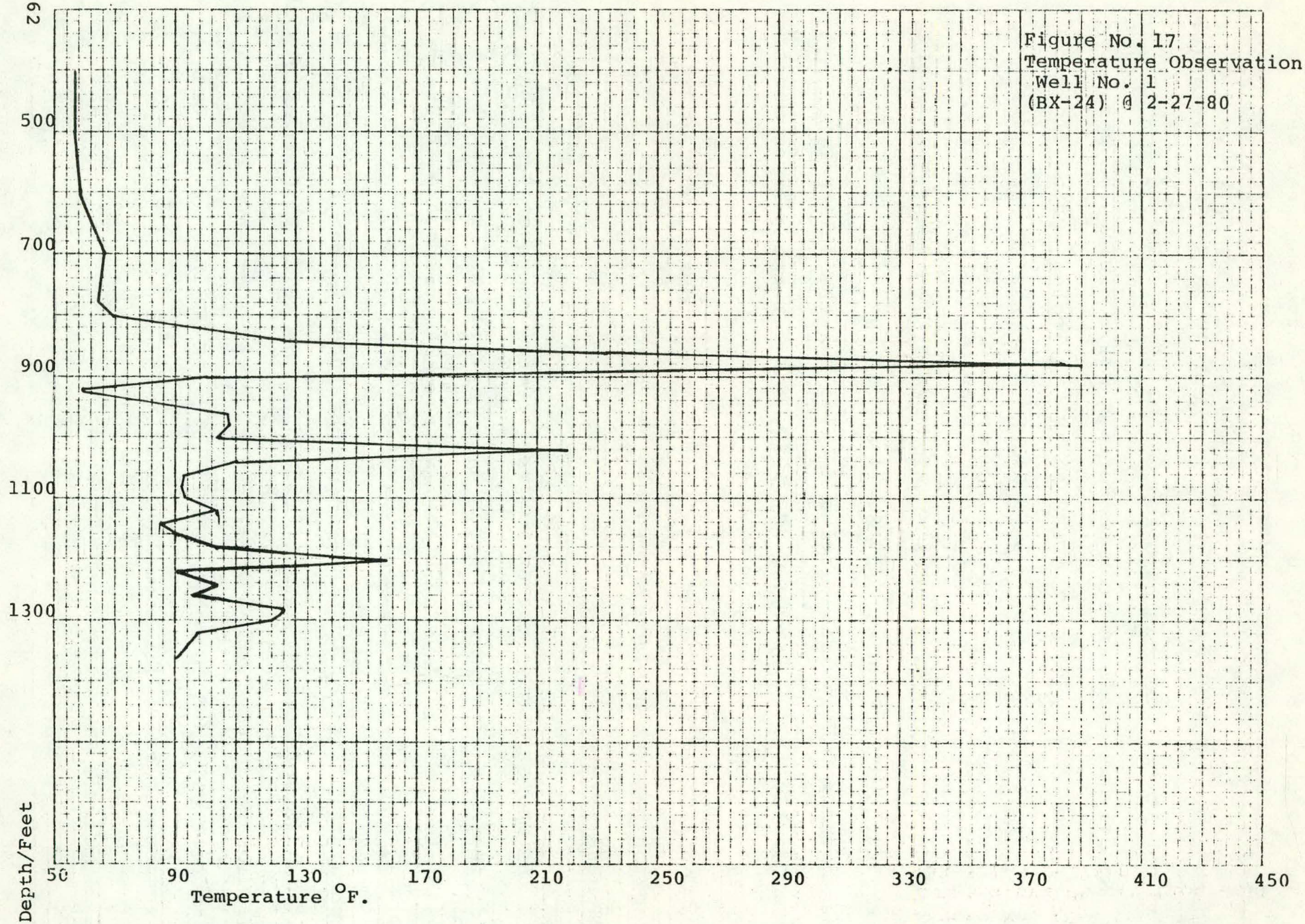


Figure No. 17
Temperature Observation
Well No. 1
(BX-24) @ 2-27-80
500
700
900
1100
1300
Depth/Feet
50
90
130
170
210
250
290
330
370
410
450
Temperature °F.

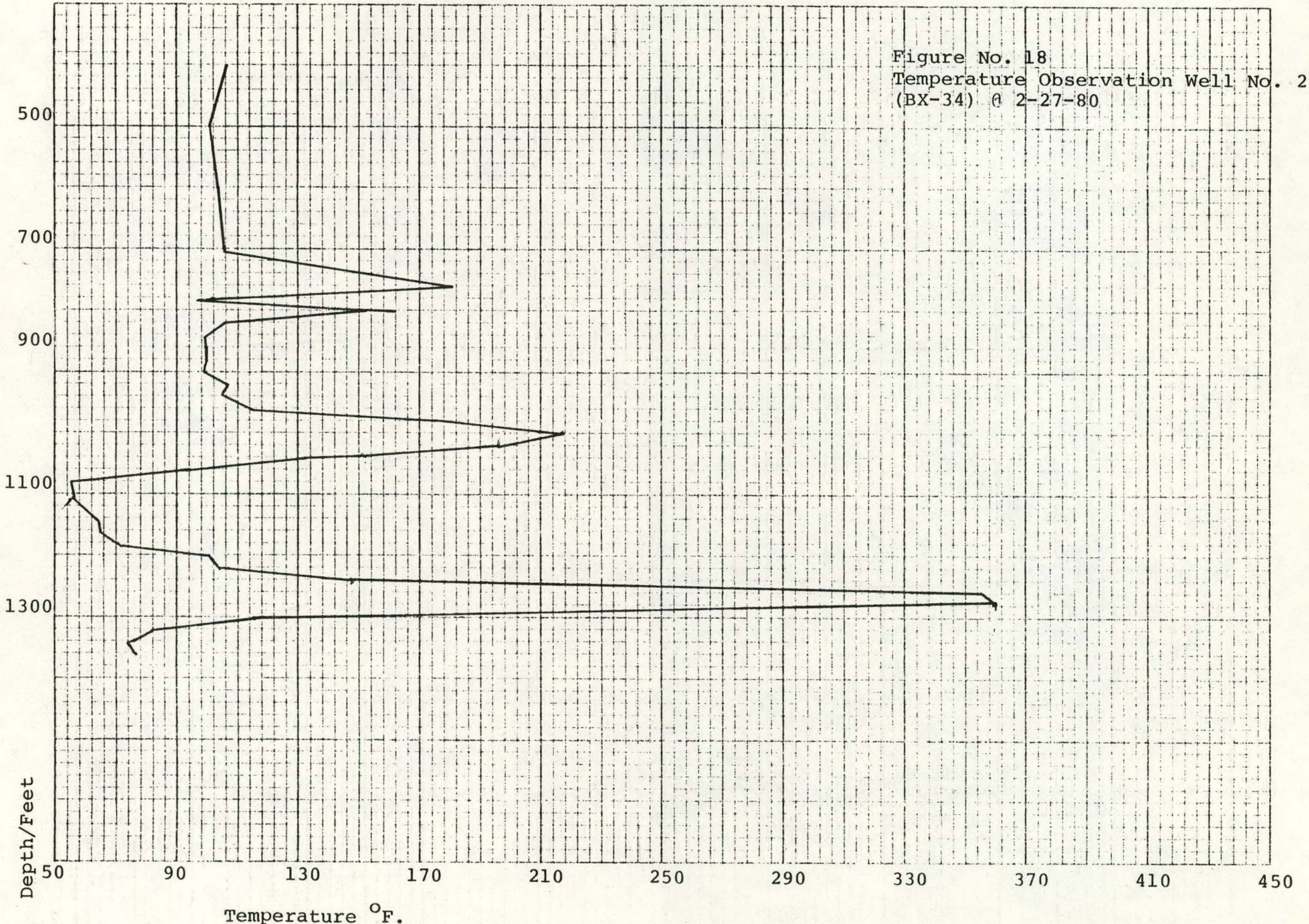


Figure No. 18
Temperature Observation Well No. 2
(BX-34) @ 2-27-80

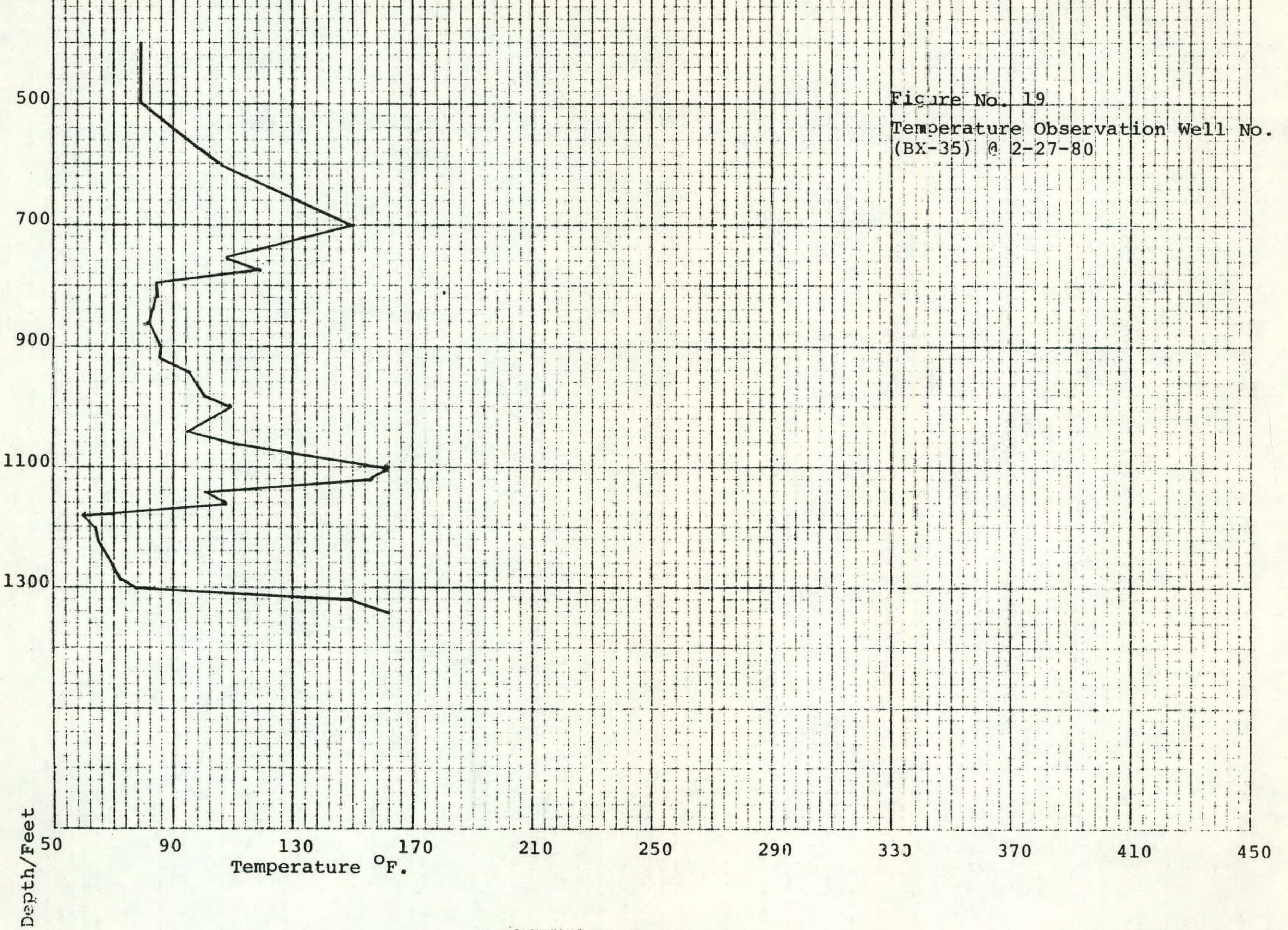


Figure No. 19
Temperature Observation Well No. 3
(BX-35) @ 2-27-80

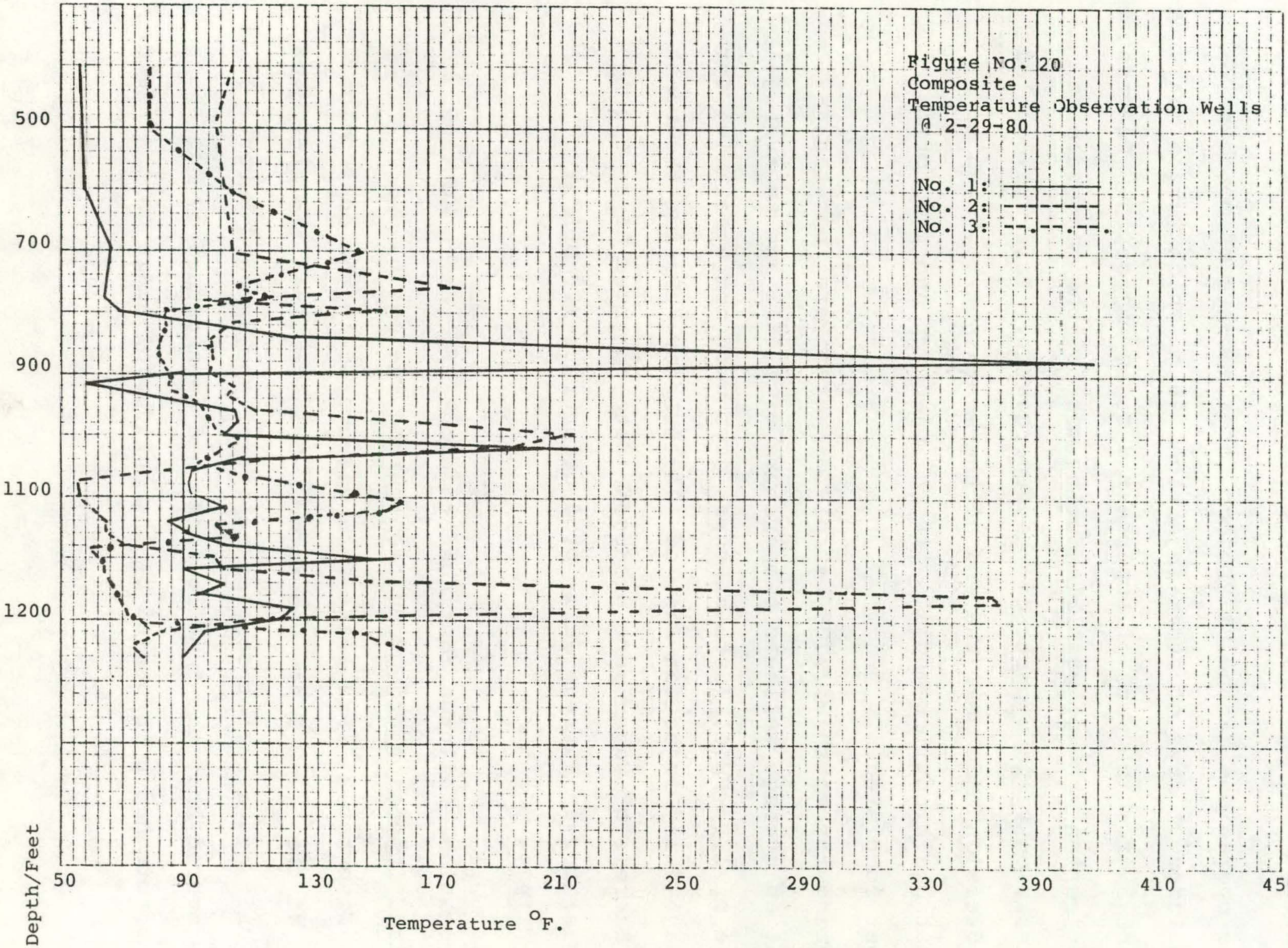


Figure No. 20
Composite
Temperature Observation Wells
@ 2-29-80

The production of water from the producing wells during the thirteen-day period averaged 780 BBLs/day compared to water injection as steam of 1761 barrels per day.

OCTOBER 1979

The operations at the BX Project for the month of October, 1979 included 31 days of steam injection, 26 of which were of saturated steam and 5 of which were of superheated steam injection. Superheated steam injection was not possible during most of the month due to small leaks on various parts of the superheater. This was coupled with a decision made near the end of the month not to go up to superheat again until remedial work on injection and production wells was completed.

During the month, 53,738 barrels of water were injected as steam at an average wellhead temperature of 514^{O}F. and an average pressure of 1303 PSIG, (data on three days were not available) for an average daily injection rate of 1919 BBL/day. During the month 20,432 barrels of water were produced (data on three days were not available) for an average daily production rate 729 BBL/day.

NOVEMBER 1979

Mechanical failures continued to block efforts to achieve stabilized injection and production during the month.

On November 2, 1979 leaks were discovered in the convection section of the No. 2 Steam Generator. This required the shut down of the unit and a rather complex repair of the damaged tubes. It was discovered that the tube failures had been caused by hot spots which in turn had been caused by the buildup of scale on the inside of the tubes. The scale buildup was caused by hard water getting past the water treating system due to an apparent sequencing failure at one of the water softeners. This failure appeared to be related to the series of power outages which occurred during the latter part of October, 1979. The damaged tubes were removed and replaced by code qualified welders, and the repair work was inspected by a code inspector.

During the month, 25,971 barrels of water were injected as steam at an average wellhead temperature of 471°F. and an average pressure of 1063 PSIG.

There were three distinct periods of injection during the month. The first was November 1st through November 7th during which saturated steam was injected at an average rate of 1225 BBL/day, an average wellhead temperature of 480°F., and an average pressure of 1293 PSIG. The second was from November 8th through November 20th during which steam was injected at an average rate of 783 BBL/day, an average wellhead temperature of 501°F. and an average pressure of 946 PSIG. The third was from November 21st through November 30th during which saturated steam was injected at an average rate of 1216 BBL/day, an average wellhead temperature of 458°F., and an average pressure wellhead of 1007 PSIG.

DECEMBER 1979

In December, 37,100 barrels of water as steam were injected into the eight injection wells at an average daily rate of 1196 barrels per day, an average wellhead temperature of 494°F., and an average pressure of 1149 PSIG. Superheated steam injection took place on only 4½ days of the month due to continued problems with leaks in the superheater. For the balance of the days, steam was injected at a saturated temperature of approximately 590^{o}F. at the outlet of the steam generator.

Saturated steam generation for the month was accomplished using Steam Generators No. 1 and No. 2 for the first nine days and Steam Generator No. 2 for the remaining 22 days.

Leaks in the tube return ends of Steam Generator No. 1 developed on December 13th. These leaks coincided with a cracked tee on the superheater, but did not result from the same cause. After repairs, both Steam Generator No. 1 and the superheater were hydrotested. Both units passed the hydrotest, but when heat-up of the superheater began again a new leak associated with a welded connection developed.

With the continuing history of leaks in the superheater, it was decided to radiograph a representative sample of the welds on the outside piping of the superheater which might present a safety hazard if a leak occurred. Any welds found to not pass radiographic inspection would be rewelded to code.

With the inability to inject at superheat, the stabilized operation of the Project was not possible. Some improvement in production was accomplished by more careful operation of the gas lift system. However it appeared that most of the production wells were operating in a slug flow mode instead of a continuous flow mode. It appears that the only way to achieve adequate and continuous production is to install a positive pumping system such as a rod pump in the production wells.

JANUARY 1980

In January, 1980, 42,245 barrels of saturated steam were injected into the eight injection wells at an average daily injection rate of

1416 barrels per day, an average wellhead temperature of 465^{o}F. and an average wellhead pressure of 1314 PSIG. Only one steam generator was operated for most of the month, and no superheated steam was injected during January.

Recurring leaks at welds in the superheater resulted in the radiographic inspection of a number of welds on the superheater piping. After radiographic inspection of 60 welds and the inspection of the X-ray films and the welds themselves by Stearns-Roger personnel and representatives of Thermotics Inc., it was determined that at least 28 welds would have to be repaired, and that approximately 100 other welds would have to be inspected and repaired if found to be defective. A bid to do the repair work was solicited from Stearns-Roger. After considering the bid and the amount of work to be done, the manufacturer, Thermotics Inc., elected to effect the required repairs. This work was initiated on February 14, 1980 and was expected to take two to four weeks.

Current operational plans call for the operation of both steam generators at maximum output pressure and temperature to maximize the saturated steam injection rate.

Production for the month equalled approximately 66% of the injected volume.

FEBRUARY 1980

In the first 27 days of February, 1980, 43,270 barrels of water as saturated steam were injected into the eight injection wells at an average daily injection rate of 1638 barrels per day. Injection data for the 28th and 29th was lost due to a flaw on a diskette and power outages, but the injection rates for those days were very close to the monthly average. Wellhead injection pressure averaged 1371 PSIG, and wellhead injection temperature averaged 472°F.

For most of the month, both steam generators were operating. Operators were instructed to operate the generators as close to design pressure as possible and maximize the amount of steam injected.

The continuing imbalance between injection and production, which is a ratio of approximately 2 to 1, must be resolved if the injection is to increase and if the Project is to operate on the most basic of its assumptions, i.e. water withdrawals from the formation must, at minimum, supply all injection needs, and at least equal injection but preferably exceed it. The scheduled Project review meeting on March 6th is to be held to address solutions to this specific problem.

ENVIRONMENTAL MONITORING (M00)

During the year, pre-start up environmental monitoring and operational environmental monitoring continued in accordance with the Environmental Research Plan. Delay in Project start up and other factors have necessitated some modifications to the original plan, and a revised Environmental Research Plan and budget was submitted to the Department of Energy for approval in September, 1979.

Appendix "H" contains the following reports prepared by VTN, Inc.

(1) Quarterly Environmental Research Plan Report December 1, 1979 - February 29, 1980.

(2) Quarterly Air Resources Report September - November 1979.

In addition to the above reports and the regular monthly and quarterly reports filed during the year, the following special reports required under the Environmental Research Plan were published during the year:

Surface Water Hydrology of the Piceance Creek Basin and BX In Situ Oil Shale Project - December 26, 1979

Geology and Geohydrology Elements of the Environmental Research Plan, BX In Situ Oil Shale Project, Rio Blanco County, Colorado - February 4, 1980

PROJECT MANAGEMENT AND CONSULTANTS (000)

During the year, the following Equity Oil Company employees were active in matters relating to the BX Project:

NAME	TITLE
Paul M. Dougan	Project Manager
Tom Wolter	Project Operations Engineer
Dallas Goodrich	Project Field Superintendent

During the year, the following consultants worked on the BX Project:

NAME	TITLE
Fred S. Reynolds	Project Engineer
Dean Gray	Legal Review
Glen Hatch	Legal Review
Dr. Paul J. Root	Mathematical Modeling & Consultant
Dr. George R. Hill	Laboratory Research Consultant

During the year, the following Stearns-Roger Corporation personnel were assigned to the Project:

NAME	TITLE
Tom Holen	Operations Supervisor
Gordon Cook	Operator
George Fergueson	Shift Supervisor
Randall Woods	Instrumentation Operator
Mike Hutton	Operator
Anthony Testa	Operator

SUMMARY

During the last year, the construction and installation of the field Project was completed, and continuous steam injection was initiated on September 18, 1979.

Mechanical problems associated with the steam generating equipment coupled with production and injection problems have thus far prevented the operation of the Project at design conditions. The results of injection to date are quite encouraging as evidenced by the temperature increases observed in Project temperature observation wells.

Mechanical and reservoir problems with the Project should be resolved during the first quarter of the present year, and operation of the Project reasonably close to design conditions for the balance of the year is expected.

Paul M. Dougan

PAUL M. DOUGAN
Project Manager

APPENDIX "A"

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LEACHED ZONE THREE DIMENSIONAL GEOHYDROLOGIC TESTING AND ANALYSIS REPORT
BX IN SITU OIL SHALE PROJECT
RIO BLANCO COUNTY, COLORADO

Submitted to:

Equity Oil Company
Salt Lake City, Utah

July 19, 1979

By:

VTN Consolidated, Inc.
2301 Campus Drive
Irvine, California 92713

Walter W. Loo (Geohydrologist)
Dale E. Markley (Hydrogeologist)
Swain D. Munson (Hydrologist)

ACKNOWLEDGEMENTS

Special thanks are extended to the personnel of Equity Oil Company and the Stearns-Roger Company for their assistance and use of their facilities at the project site. Their help was essential in the compilation of data for this report.

SUMMARY

The leached zone or lower aquifer in the BX well field area is anisotropic.

The ratio of major horizontal permeability, minor horizontal permeability and vertical permability in the leached zone is 14.7:13.3:1 respectively or 199 md:180 md:13.5 md.

The average horizontal transmissivity of the leached zone is 1,809 gpd/ft with an upper leached zone value of 987 gpd/ft and a lower leached zone value of 922 gpd/ft.

The average horizontal permeability of the leached zone is about 189md.

The average storage coefficient is about 1.54×10^{-3} for the leached zone.

The rate of ground water movement in the leached zone is about 23.4 feet per year due north across the BX In Situ Oil Shale Project site.

The contrast of horizontal to vertical permeability is large. It will cause less than satisfactory vertical sweep by the present well perforation designs.

A combined flow and geochemical model is recommended for future well field simulation. The model has to be calibrated with data obtained from the present operation.

A calibrated model coupling with optimization techniques can be used to minimize the cost of the production well field.

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LIST OF FIGURES

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SECTION 1.0

INTRODUCTION

This report presents a three dimensional geohydrologic analysis of aquifer tests run at the BX In Situ Oil Shale Project in Rio Blanco County, Colorado. Field testing included a pump test, an injection test and a packer test during the period May 12 to June 10, 1979. The aquifer analyzed was the leached zone of the Parachute Creek Member of the Green River Formation. Ground water movement determination was also analyzed.

SECTION 2.0

GEOHYDROLOGIC TEST AND ANALYSIS OF THE PRODUCTION HORIZON

2.1 Geohydrologic Testing

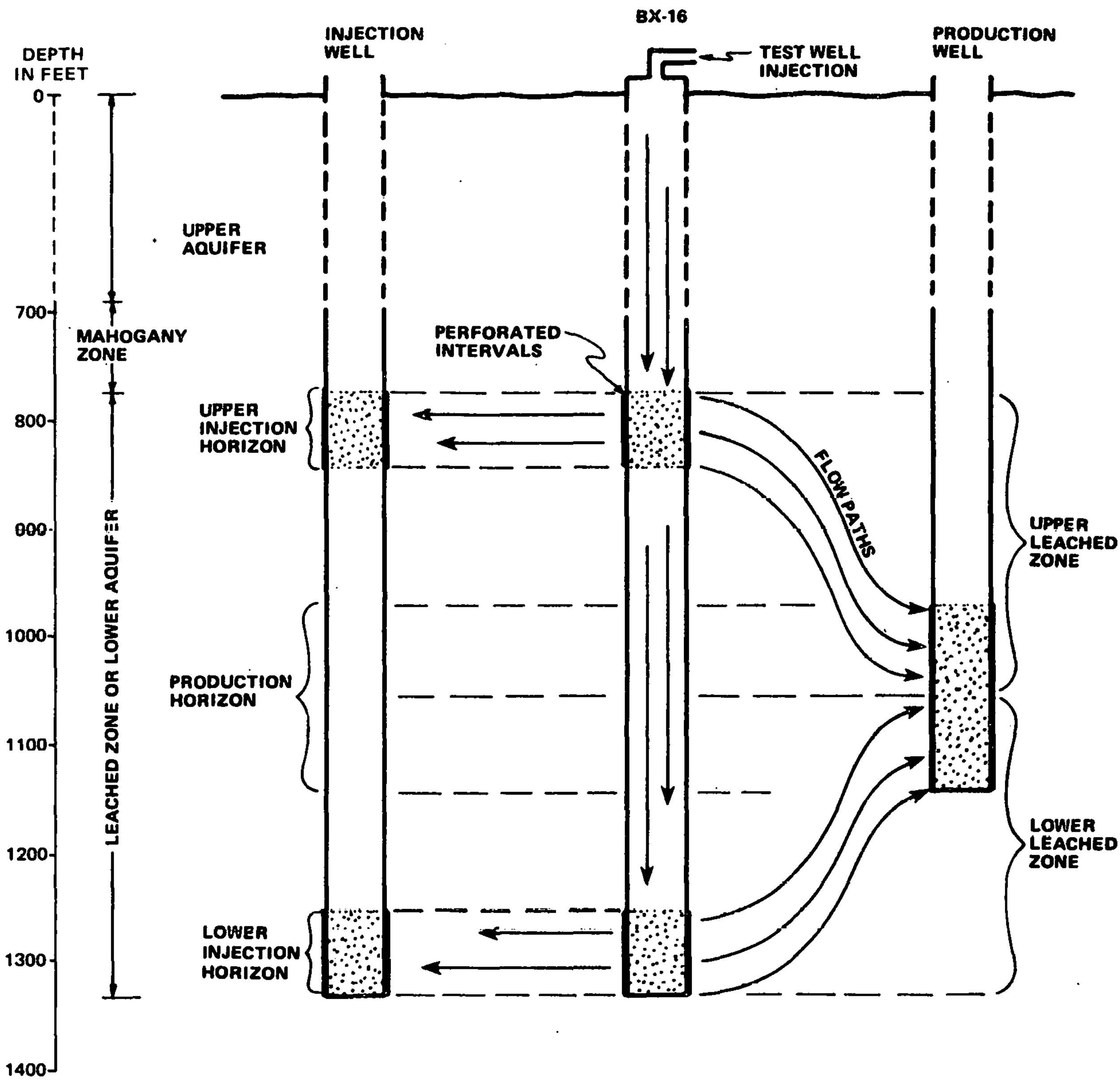
A 24-hour drawdown test and 24-hour recovery test were performed on the production horizon of the leached zone (or lower aquifer) at the BX In Situ Oil Shale Project Site during May 12-14, 1979 (see Figure 1). The drawdown test was run at a constant rate of about 13 gpm or 445 barrels per day.

BX-26 was used as the pumping well and 20 other wells at the project site were used as observation wells (see Figure 2). Table 1 is a tabulation of the elevation and perforated interval of wells used in geohydrologic testing. All wells are completed in the leached zone (approximately 780 to 1400 feet below the land surface) with the exception of BX-6 and BX-8 which are completed in the upper aquifer (approx. 500 to 550 feet below land surface).

Since gas pressure was bled off from BX-14 and BX-20 immediately before the start of the drawdown test, the data on the drawdown test cannot be used for analysis because of partial recovery influence. However, the partial recovery was overcome at about 10 hours after start of pumping. The 24-hour recovery data is good for geohydrologic analysis.

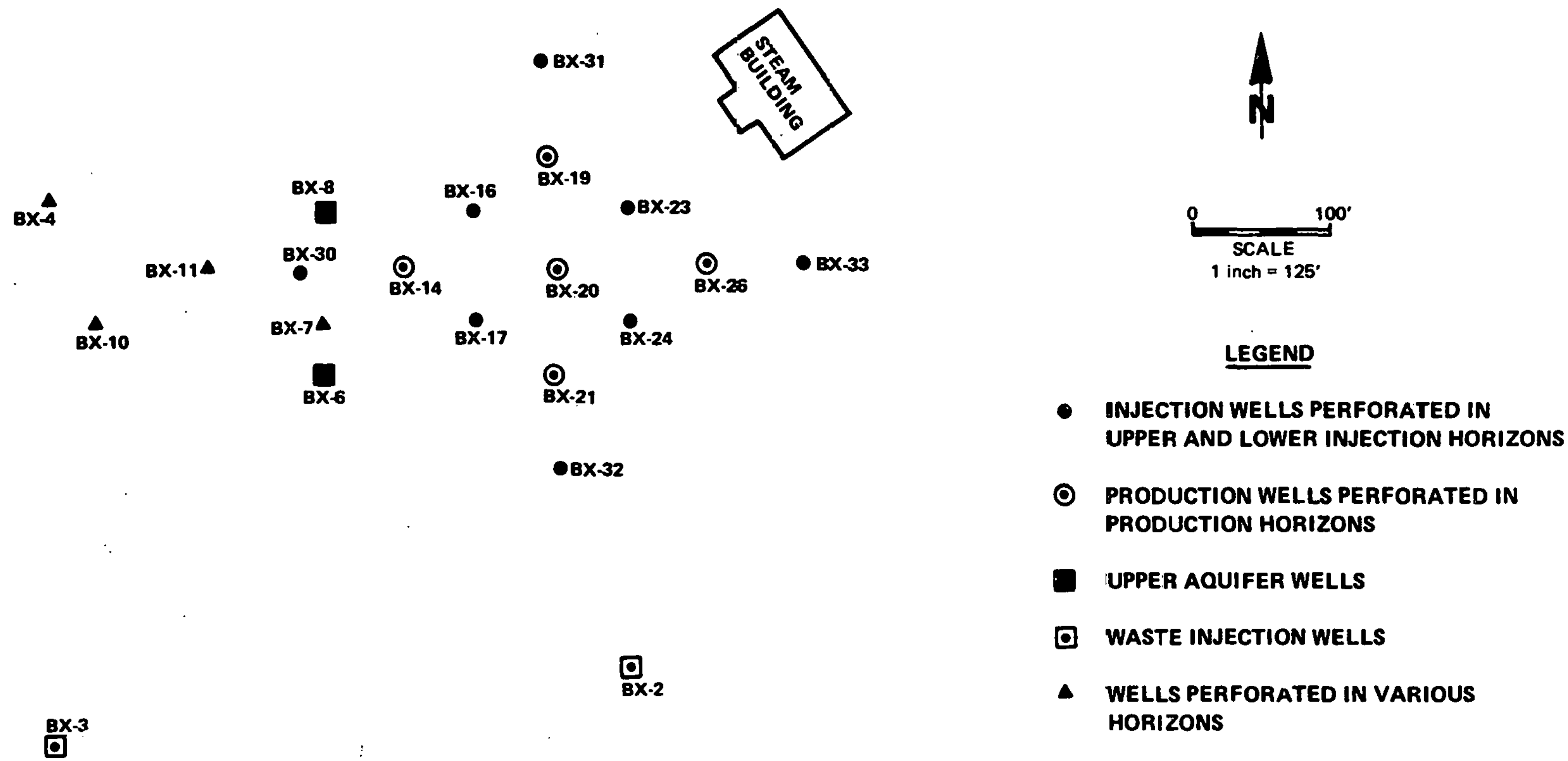
2.2 Geohydrologic Analysis

During the entire 48-hour testing program, only three wells showed positive response to the pumping effects of BX-26 and they are BX-19, BX-20, and BX-21. BX-14 showed only 0.8 feet of recovery after 24 hours which is not enough for analysis. The recovery responses on BX-19, BX-20 and BX-21 were 4.3 feet, 5.4 feet and 5.9 feet, respectively.



LEACHED ZONE GEOHYDROLOGIC NOMENCLATURES AND FLOW TEST SCHEME OF BX IN SITU OIL SHALE PROJECT AREA, RIO BLANCO COUNTY, COLORADO

FIGURE 1



GROUND SURFACE LOCATION OF WELLS USED IN GEOHYDROLOGIC TESTING

BX IN SITU OIL SHALE PROJECT
RIO BLANCO COUNTY, COLORADO

FIGURE 2

TABLE 1 (continued)

WELL NUMBER	SURFACE ELEVATION (in feet)	DEPTH OF PERFORATED INTERVAL (in feet)
Waste Injection Wells		
BX - 2	6650	1101-1229
BX - 3	6622	1058-1191
Wells Perforated in Various Horizons		
BX - 4	6616	1075-1215
BX - 7	6630	810-998
BX - 10	6617	776-984
BX - 11	6629	776-984

Equations used in the geohydrologic analysis are presented in Table 2, with the results of geohydrologic analysis summarized in Table 3. The section of the leached zone tested (983 to 1278 feet below land surface), referred to as the production horizon, shows an average permeability of about 1.3 gpd/ft.^{2} or 70 millidarcies. Since the storage coefficient values are relatively close, the contrast of horizontal permeability tensors are not expected to be of great concern with the present well field configuration or design.

It is of the greatest concern that observation wells BX-16, BX-17, BX-23, BX-24 and BX-33 did not show any response during the test period. These wells are within a 200-foot radius of the pumping well and are completed in different horizons within the leached zone. The radius of pressure cone had spread about 250 feet during the test period.

TABLE 2

EQUATIONS USED IN GEOHYDROLOGIC ANALYSIS
OF THE PRODUCTION HORIZON

$$T = \frac{264\ Q}{\Delta s}$$

$$S = \frac{0.3\ T\ t_o}{r^2}$$

$$K = \frac{T}{b}$$

T = transmissivity, in gpd per foot

Q = pumping rate, in gpm

Δs = change in drawdown for 1 log cycle on time - drawdown graph, in feet

S = storage coefficient

t_o= intercept of straight line in time-draw down graph at zero drawdown, in days

r = horizontal distance, in feet, from bottom of pumped well to bottom of observation well

K = hydraulic conductivity, in gpd per square foot or millidarcies (md)

b = saturated thickness of aquifer, in feet

NOTE: Taken from Ground Water and Wells, 1966.

TABLE 3

SUMMARY OF GEOHYDROLOGIC ANALYSIS
FOR PRODUCTION HORIZON

	UNITS	BX-19	BX-20	BX-21	AVERAGE VALUES
Q	in gpm	13	13	13	13
Δs	in ft.	7.4	10	10.8	9.4
t_o	in days	.243	.278	.278	.266
r	in ft.	132	102	108	114
T	in gpd/ft.	464	343	318	375
b	in ft.	295	295	295	295
K	in gpd/ft^2	1.57	1.16	1.08	1.27
K	in md	86.4	63.8	59.4	69.9
S		1.941×10^{-3}	2.749×10^{-3}	2.274×10^{-3}	2.321×10^{-3}

SECTION 3.0

GEOHYDROLOGIC TEST AND ANALYSIS OF THE LEACHED ZONE

3.1 Geohydrologic Testing

A 43-hour injection test and 31-hour recovery test were performed on the leached zone during June 4-7, 1979. The injection test was run at a constant rate of 50 gpm or 1714 barrels per day with approximately 400 psi at the well head. BX-16 was used as the injection well with 20 other wells at the project site used as observation wells (see Figure 2).

The well field was stable prior to the beginning of injection with the exception of BX-2 and BX-3. BX-2 was injected with waste brine approximately 3 hours before the test began and therefore showed a decline in head for the first 16 hours of the test. The effects of injection at BX-2 apparently affected the water level in BX-3 which also showed a decline in head for the first 40 hours.

3.2 Geohydrologic Analysis

During the duration of the injection test an increase in water level was observed in all observation wells with the exception of BX-2, BX-3 and BX-4. BX-4 showed no change whereas BX-2 and BX-3 were affected by prior injection as mentioned. The static water level, depth of water level prior to test and the change in water level after 43 hours of injection are summarized in Table 4. The change in water level with time since injection began for the injection portion of the test is tabulated in Appendix A for wells not affected by partial penetration effects.

TABLE 4

DEPTH TO WATER LEVEL IN OBSERVATION WELLS USED IN INJECTION TEST June 4-7, 1979

Well Number	Approximate Well Collar Height Above Ground Surface (in feet)	Depth To Static Water Level Before Test* (in feet)	Depth To Water Level After 43 Hours Of Injection* (in feet)	Change In Water Level (in feet)
Injection Wells Perforated In Upper and Lower Injection Horizon				
BX - 17	6.3	18.0	OF	>18.0
BX - 23	8.2	19.4	OF	>19.4
BX - 24	8.1	22.4	OF	>22.4
BX - 30	6.4	18.7	OF	>18.7
BX - 31	6.3	17.0	OF	>17.0
BX - 32	8.6	21.1	OF	>21.1
BX - 33	8.3	21.5	OF	>21.5
Production Wells Perforated In Production Horizon				
BX - 14	4.7	21.3	20.1	+ 1.2
BX - 19	5.0	24.4	22.4	+ 2.0
BX - 20	4.6	25.5	23.9	+ 1.6
BX - 21	4.8	26.5	25.0	+ 1.5
BX - 26	5.7	21.9	19.7	+ 2.2
Upper Aquifer Wells				
BX - 6	4.0	22.6	20.3	+ 2.3
BX - 8	0	15.5	13.0	+ 2.5
Waste Injection Wells				
BX - 2	5.7	36.2	37.7	-1.5
BX - 3	5.3	13.4	14.2	-0.8
Wells Perforated in Various Horizons				
BX - 4	0.8	1.3	1.3	0
BX - 7	6.0	17.7	OF	>17.7
BX - 10	5.5	7.3	OF	> 7.3
BX - 11	4.2	17.4	OF	>17.4

* Measurements taken from top of well collar.

OF Overflowing, closed valve.

The following analysis is divided into horizons of perforation and zones of flow expected during the in situ process. The divisions of perforated intervals are: 1) observation wells perforated in the same or similar intervals as BX-16 and, 2) production wells perforated at intervals different from BX-16. These divisions are analyzed as the upper and lower injection horizons and the upper and lower leached zones. Figure 1 illustrates the general flow test scheme and geohydrologic nomenclatures of the leached zone.

3.2.1 Geohydrologic Analysis for Upper and Lower Injection Horizons

Wells tabulated on Table 5 are perforated in the upper and lower injection horizons which are the same intervals as BX-16. The analysis of data from these wells indicate the aquifer characteristics of the upper and lower injection horizons. These are approximately the intervals in depth of 785 to 847 and 1260 to 1340 feet of the leached zone. These horizons have an average permeability of about 5.6 gpd/ft.^{2} or 308 millidarcies and a storage coefficient of 7.5×10^{-4}.

3.2.2 Geohydrologic Analysis of the Upper and Lower Leached Zone

The analysis of the upper and lower leached zones (see Tables 6 and 7) assumes that the horizontal permeability and storage coefficient of these zones are equal for each zone for all production wells. This value is equal to the average of the values for the production wells from the first test (Table 3) and the values from wells completed to the upper and lower injection horizons (Table 5). The average permeability was 3.44 gpd/ft.^{2} or 189 millidarcies and the average storage coefficient was 1.54×10^{-3}.

The upper leached zone is approximately located in the interval between 785 to 1072 feet of depth. This zone has an average transmissivity of 987 gpd/ft.

TABLE 5

SUMMARY OF GEOHYDROLOGIC ANALYSIS FOR
UPPER AND LOWER INJECTION HORIZONS

	Units	Well Numbers BX-17	BX-23	BX-24	BX-30	BX-31	BX-32	BX-33	Average Values
Q	in gpm	50	50	50	50	50	50	50	50
Δs	in ft.	11.2	7.7	11.6	13.6	11.6	12.0	7.3	10.7
t_o	in days	0.174	.0278	.0486	.0090	.0139	.326	.057	.0714
r	in ft.	92	88	140	152	176	212	152	144.6
T	in gpd/ft.	985	1128	746	754	1138	971	717	920
b	in ft.	163	162	166	157	157	181	158	164
K	in gpd/ft^2	6.04	6.96	4.49	4.80	7.25	5.34	4.54	5.61
K	in md	332	383	247	264	398	293	249	308
S		6.1×10^{-4}	1.2×10^{-3}	5.5×10^{-4}	8.8×10^{-5}	1.5×10^{-4}	2.1×10^{-3}	5.3×10^{-4}	7.5×10^{-4}

TABLE 6

SUMMARY OF GEOHYDROLOGIC ANALYSIS FOR
FOR THE UPPER LEACHED ZONE

	Units	Well Numbers: BX-14	BX-19	BX-20	BX-21	BX-26	Average Values
Avg.Q	in gpm	22	22	22	22	22	22
r	in ft.	100	40	52	120	140	90.4
T	in gpd/ft.	943	956	956	901	1187	987
b	in ft.	274	278	278	262	345	287
Avg.K	in gpd/ft^2	3.44	3.44	3.44	3.44	3.44	3.44
Avg.K	in md	189	189	189	189	189	189
Avg.S	(x 10^{-3})	1.54	1.54	1.54	1.54	1.54	1.54
Kh/Kv		14.07	12.47	14.47	11.25	8.18	12.09
Kv	in gpd/ft^2	0.24	0.28	0.24	0.31	0.42	0.30
Kv	in md	13.45	15.17	13.07	16.82	23.12	16.33

TABLE 7

SUMMARY OF GEOHYDROLOGIC ANALYSIS FOR FOR THE LOWER LEACHED ZONE

		Well Numbers					
	Units	BX-14	BX-19	BX-20	BX-21	BX-26	Average Values
Avg.Q	in gpm	28	28	28	28	28	28
r	in ft.	100	40	52	120	140	90.4
T	in gpd/ft.	967	953	953	1008	722	922
b	in ft.	281	277	277	293	210	268
Avg.K	in gpd/ft^2	3.44	3.44	3.44	3.44	3.44	3.44
Avg.K	in md	189	189	189	189	189	189
Avg.S	($x10^{-3}$)	1.54	1.54	1.54	1.54	1.54	1.54
Kh/Kv		22.08	13.04	14.62	N.S.	N.S.	16.58
Kv	in gpd/ft^2	0.16	0.26	0.24	N.S.	N.S.	0.22
Kv	in md	8.57	14.51	12.95	N.S.	N.S.	12.01

N.S. - no solution

The lower leached zone is approximately located in the interval between 1072 to 1340 feet of depth. This zone has an average transmissivity of 922 gpd/ft.

3.2.3 Geohydrologic Analysis of Vertical Permeability of the Leached Zone

Production wells BX-14, BX-19, BX-20, BX-21 and BX-26 are perforated at intervals different than BX-16. Water level measurements in these wells were affected by partial penetration effects. The Weeks method was used in the analysis (Weeks, 1969). Several assumptions were necessary to do computer analysis for these wells. These assumptions are listed in Table 8. Analysis of these data are summarized in Table 9.

Analysis of the upper leached zone indicates an average horizontal to vertical permeability ratio of 12.1 with an average vertical permeability of 0.28 gpd/ft.^{2} or 15.6 millidarcies.

The lower leached zone indicates an average horizontal to vertical ratio of 16.6 with an average vertical permeability of 0.21 gpd/ft.^{2} or 11.4 millidarcies.

The average values for the full extent of the leached zone are approximately a ratio of 14.35 for horizontal to vertical permeability with an average vertical permeability of 0.245 gpd/ft.^{2} or 13.5 millidarcies.

3.2.4 Reservoir Horizontal Anisotropic Analysis of the Leached Zone

An analysis of the horizontal dimension of anisotropy was performed on the upper and lower leached zones. The Papadopulos method was used in the analysis (Papadopulos, 1965). This analysis was based on flow from BX-16 to the production wells. The same assumptions were used as in

TABLE 8

ASSUMPTIONS USED IN GEOHYDROLOGIC ANALYSIS

I. Transmissivity and storage coefficient are equal for all production wells. These are equal to the average of the values for the production wells from the first test (Table 4) and the values from wells completed to the upper and lower injection horizons (Table 5).

II. Fluid flow can be divided into two components of flow. These components are vertical and horizontal flow paths.

   A. Vertical permeability was analyzed with the following assumptions:

      1. Vertical flow is divided and confined to the upper and lower leached zones.

         a. Upper leached zone: flow in this zone is confined between the top of the upper perforated interval of BX-16 and the middle of the perforated interval of the production wells.

         b. Lower leached zone: flow in this zone is confined between the bottom of the lower perforated interval of BX-16 and the middle of the perforated interval of the production wells.

   B. The horizontal anisotropy of the leached zone required correction for partial penetration effects. This required analysis of the amount of change in water level that would be expected if the production wells were completed to the same interval as BX-16. Therefore, all flow would be in the horizontal dimension. Horizontal anisotropy was analyzed with the following assumptions:

      1. Horizontal flow is divided and confined to the upper and lower leached zones.

         a. Upper leached zone: flow is in a horizontal direction and is confined between the top of the perforated interval of BX-16 and the middle of the perforated interval of the production well.

         b. Lower leached zone: flow is in a horizontal direction and is confined between the bottom of the lower perforated interval of BX-16 and the middle of the perforated interval of the production wells.

TABLE 8 (continued)

ASSUMPTIONS USED IN GEOHYDROLOGIC ANALYSIS

c. The upper and lower leached zones represent 44 and 56 percent of the aquifer thickness respectively. Therefore the same percent of the injected water at BX-16 is flowing in these zones. This is approximately 22 gpm in the upper leached zone and 28 gpm in the lower leached zone.

TABLE 9

SUMMARY OF THE GEOHYDROLOGIC ANALYSIS OF THE HORIZONTAL AND VERTICAL PERMEABILITY OF THE LEACHED ZONE

	Average Horizontal Permeability		Average Vertical Permeability		Ratio of Horizontal to Vertical Permeability
	gpd/ft^2	md	gpd/ft^2	md	
Upper Leached Zone	3.44	189	0.28	15.6	12.09
Lower Leached Zone	3.44	189	0.21	11.4	16.58
Average Values	3.44	189	0.25	13.5	14.34

the vertical permeability analysis. In addition an interpretation of the anticipated change in head with no partial penetration effects were made in the computer analysis. The results of this analysis (Tables 10 and 11) indicate major and minor horizontal transmissivities of 1048 and 931 gpd/ft. in the upper leached zone. The direction of major transmissivity was N 78° E.

In the lower leached zone the major and minor transmissivities were 960 and 885 gpd/ft., with the direction of major transmissivity of N 73° W. The contrast in major and minor transmissivity is very small indicating fairly isotropic conditions in the horizontal dimension of the leached zone.

TABLE 10

RESULTS OF RESERVOIR ANISOTROPIC ANALYSIS
OF THE UPPER LEACHED ZONE

Major Horizontal Transmissivity	1048 gpd/ft
Minor Horizontal Transmissivity	931 gpd/ft
Mean Horizontal Transmissivity	987 gpd/ft
Direction of Major Horizontal Transmissivity Axis	N 78° E

TABLE 11

RESULTS OF RESERVOIR ANISOTROPIC ANALYSIS
OF THE LOWER LEACHED ZONE

Major Horizontal Transmissivity	960 gpd/ft
Minor Horizontal Transmissivity	885 gpd/ft
Mean Horizontal Transmissivity	922 gpd/ft
Direction of Major Horizontal Transmissivity Axis	N 73° W

SECTION 4.0

PACKER TEST

4.1 Geohydrologic Testing

In an effort to determine a preferred direction of flow within the leached zone a packer test was conducted for 73 hours during June 7-10, 1979. This involved BX-16 as the injection well and BX-20 as the observation well. This injection test was run at a constant 100 gpm or 3428 barrels per day with approximately 470 psi at the well head.

A packer was set at a depth of 1070 feet about the middle of the perforation interval of the well. Water levels were then taken through the annulus to measure levels above 1070 feet and through the pipe to measure levels below 1070 feet (see Figure 3).

The well field was not stable prior to the beginning of the test. This was a result of recovery from the injection test and mainly due to the installation of more pipe into the hole than there was initially. This caused the water levels in both the annulus and pipe to come within 3 feet of the well collar. Injection was started after water levels declined to approximately 17 feet in the pipe and 15 feet in the annulus. The water levels continued to decline for the first 10 hours of the test at which time water levels began to rise at equal rates in both the pipe and annulus. After 73 hours of injection water levels rose above the 10 hour level by 1.3 feet in both the pipe and annulus.

4.2 Geohydrologic Analysis

The consistent and equal changes in water level in both of the intervals tested indicate that there is relatively no contrast in their permeabilities. Computer analysis to determine vertical permeability could not be analyzed due to the unstable well field conditions.

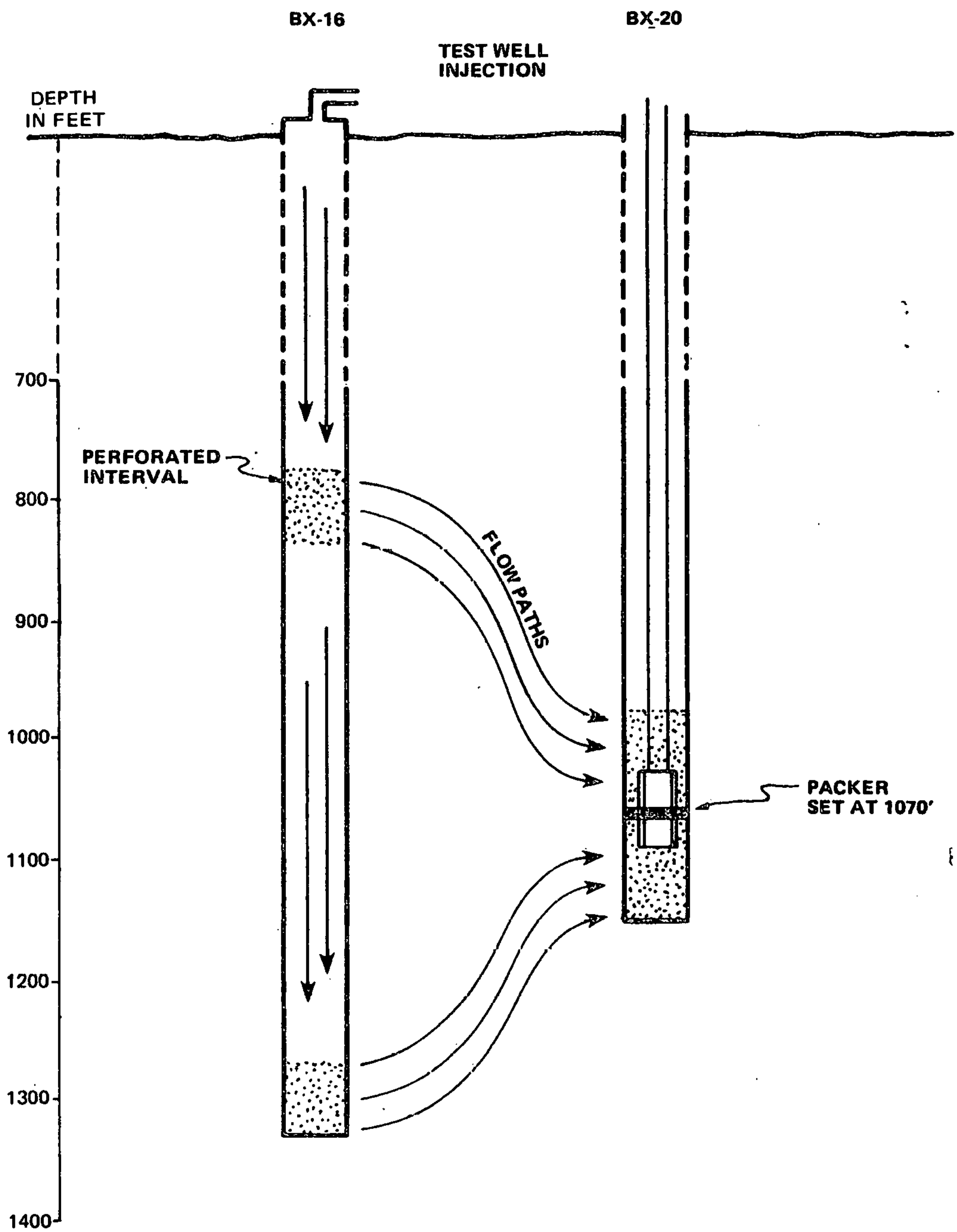


FIGURE 3

PACKER TEST GEOHYDROLOGIC FLOW SCHEME OF INJECTION TEST

JUNE 7-10, 1979

SECTION 5.0

GROUND WATER MOVEMENT

5.1 Ground Water Movement Analysis

The regional ground water movement in the leached zone can readily be determined once the permeability, ground water gradient, and porosity of the formation are known.

$$\text{rate of movement} = \frac{\text{permeability x gradient}}{\text{porosity}}$$

average permeability = 3.44 gpd/ft.^{2} or 189 millidarcies

gradient = 73.5 ft./mile or 0.013926 ft./ft.
(taken from USGS Prof. Paper 908)

assumed porosity = 0.1

approximate distance from
project site to Piceance Creek = 6 miles

The rate of ground water movement in the leached zone is estimated to be 23.4 feet per year due north across the BX In Situ Oil Shale Project site. Assuming that these values of permeability, porosity and gradient are representative of the local hydrogeology it will take the ground water in the leached zone from the project area a minimum of 1354 years to reach the Piceance Creek.

SECTION 6.0

SUMMARY AND RECOMMENDATIONS

6.1 Summary

1. The leached zone or lower aquifer in the BX well field area is anisotropic.

2. The ratio of major horizontal permeability, minor horizontal permeability and vertical permability in the leached zone is 14.7:13.3:1 respectively or 199md:180md:13.5md.

3. The average horizontal transmissivity of the leached zone is 1809 gpd/ft with an upper leached zone value of 987 gpd/ft and a lower leached zone value of 922 gpd/ft.

4. The average horizontal permeability of the leached zone is about 189md.

5. The average storage coefficient is about $1.54x10^{-3}$ for the leached zone.

6. The average horizontal permeability in the upper injection horizon, production horizon, and lower injection horizon in the leached zone are 308md, 70md, and 308md respectively.

7. The rate of ground water movement in the leached zone is about 23.4 feet per year due north across the BX In Situ Oil Shale Project site.

8. The contrast of horizontal to vertical permeability is large. It will cause less than satisfactory vertical sweep by the present well perforation designs.

6.2 Recommendations

Since the three-dimensional geohydrologic properties of the leached zone have been determined, it is possible to provide meaningful input data into any valid reservoir models. A reservoir model which can handle both the horizontal and vertical permeability is recommended. The horizontal anisotropic property of the leached zone will not be a significant factor in controlling the flow of fluid. The selected model should be able to handle high temperature, geochemistry. thermodynamics, multiple-phase fluid flow, and has general printing and plotting capabilities. With the on-going steam injection activity and data logger capability, the model should utilize these data for model calibration and fitting purposes. Once the model is calibrated, projection can be made on production curves and other simulation uses. With the addition of optimization techniques to the model, cost of production well field can then be reduced to a minimum.

SECTION 7.0

REFERENCES CITED

Groundwater and Wells, 1966, Edward E. Johnson, Inc.

Papadopulos, I.S., 1965, Nonsteady Flow to a Well in an Infinite Anisotropic Aquifer, Proceedings of the Dubrovnik Symposium, Volume 1, p. 21-31.

Weeks, E. P., 1969, Determining the Ratio of Horizontal to Vertical Permeability by Aquifer Test Analysis, Water Resources Research, vol. 5, no. 1.

Weeks, J. B. et al, 1974, Simulation Effects of Oil Shale Development on the Hydrology of Piceance Basin, Colorado, USGS Professional Paper 908.

APPENDIX A

INJECTION TEST DATA
FOR OBSERVATION WELLS NOT AFFECTED
BY PARTIAL PENETRATION EFFECTS

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LOCATION BX IN SITU OIL SHALE PROJECT

WELL # BX-7

OBSERVATION WELL X PUMPING WELL

WELL COLLAR HEIGHT ABOVE GROUND LEVEL 6.0 ft.

DEPTH TO STATIC WATER LEVEL 17.7 ft.

DATE AND TIME OF MEASUREMENT June 4, 1979 1210 hrs.

DATE	TIME (MINS)	DEPTH TO WATER (FT.)	DRAWDOWN (FT)	COMMENTS
June 4	14	17.4	+0.3	
"	24	17.0	+0.7	
"	36	16.5	+1.2	
"	48	16.1	+1.6	
"	63	15.5	+2.2	
"	90	14.8	+2.9	
"	120(2 hrs)	13.8	+3.9	
"	180(3 hrs)	12.6	+5.1	
"	240(4 hrs)	11.5	+6.2	
"	360(6 hrs)	9.8	+7.9	
"	480(8 hrs)	7.8	+9.9	
June 5	720(12 hrs	5.2	+12.5	
"	960(16 hrs	3.3	+14.4	
"	1200(20 hrs	1.5	+16.2	closed valve

LOCATION BX In Situ Oil Shale Project

WELL # BX-10

OBSERVATION WELL X PUMPING WELL

WELL COLLAR HEIGHT ABOVE GROUND LEVEL 5.5 ft.

DEPTH TO STATIC WATER LEVEL 7.3 ft.

DATE AND TIME OF MEASUREMENT June 4, 1979 1210 hrs.

DATE	TIME (MINS)	DEPTH TO WATER (FT.)	DRAWDOWN (FT)	COMMENTS
June 4	17	5.7	+1.6	
"	27	5.7	+1.6	
"	38	5.7	+1.6	
"	51	5.6	+1.7	
"	67	5.5	+1.8	
"	90	5.3	+2.0	
"	120(2 hrs)	5.0	+2.3	
"	180(3 hrs.)	4.8	+2.5	
"	240(4 hrs.)	4.3	+3.0	
"	360(6 hrs)	3.3	+4.0	
"	480(8 hrs)	2.3	+5.0	
June 5	720(12 hrs)	1.0	+6.3	closed valve

LOCATION BX In Situ Oil Shale Project

WELL # BX-11

OBSERVATION WELL X PUMPING WELL

WELL COLLAR HEIGHT ABOVE GROUND LEVEL 4.2 ft.

DEPTH TO STATIC WATER LEVEL 17.4 ft.

DATE AND TIME OF MEASUREMENT June 4, 1979 1215 hrs.

DATE	TIME (MINS)	DEPTH TO WATER (FT.)	DRAWDOWN (FT)	COMMENTS
June 4	16	14.0	+3.4	
"	26	12.8	+4.6	
"	37	11.9	+5.5	
"	49	11.3	+6.1	
"	65	10.6	+6.8	
"	90	9.6	+7.8	
"	120(2 hrs)	7.9	+9.5	
"	180(3 hrs)	6.6	+10.8	
"	240(4 hrs)	5.0	+12.4	
"	360(6 hrs)	3.0	+14.4	
"	480(8 hrs)	1.5	+15.9	closed valve

LOCATION BX In Situ Oil Shale Project

WELL # BX-17

OBSERVATION WELL X PUMPING WELL

WELL COLLAR HEIGHT ABOVE GROUND LEVEL 6.3 ft.

DEPTH TO STATIC WATER LEVEL 18.0 ft.

DATE AND TIME OF MEASUREMENT June 4, 1979 1220 hrs.

DATE	TIME (MINS)	DEPTH TO WATER (FT.)	DRAWDOWN (FT)	COMMENTS
June 4	1	17.8	+0.2	
"	3	17.3	+0.7	
"	5	16.5	+1.5	
"	7	15.8	+2.2	
"	10	15.0	+3.0	
"	21	13.1	+4.9	
"	32	11.9	+6.1	
"	43	11.1	+6.9	
"	60	10.4	+7.6	
"	90	9.2	+8.8	
"	120(2 hrs)	7.6	+10.4	
"	180(3 hrs)	6.3	+11.7	
"	240(4 hrs)	4.7	+13.3	
"	360(6hrs)	2.6	+15.4	
"	480(8hrs)	1.0	+17.0	closed valve

LOCATION BX IN SITU OIL SHALE PROJECT

WELL # BX-23

OBSERVATION WELL X PUMPING WELL

WELL COLLAR HEIGHT ABOVE GROUND LEVEL 8.2 ft.

DEPTH TO STATIC WATER LEVEL 19.4 ft.

DATE AND TIME OF MEASUREMENT June 4, 1979 1210 hrs.

DATE	TIME (MINS)	DEPTH TO WATER (FT.)	DRAWDOWN (FT)	COMMENTS
June 4	1	19.4	0	
"	5	19.4	0	
"	10	18.7	+0.7	
"	21	17.6	+1.8	
"	30	16.6	+2.8	
"	37	16.2	+3.2	
"	60	15.2	+4.2	
"	91	14.1	+5.3	
"	120(2 hrs)	12.9	+6.5	
"	180(3 hrs)	12.5	+7.9	
"	240(4 hrs)	10.2	+9.2	
"	360(6 hrs)	8.4	+11.0	
"	480(8 hrs)	6.8	+12.6	
June 5	720(12 hrs)	4.5	+14.9	
"	960(16 hrs)	2.6	+16.8	
"	1080(18 hrs	1.8	+17.6	
"	1200(20 hrs	0.8	+18.6	closed valve

LOCATION BX IN SITU OIL SHALE PROJECT

WELL # BX-24

OBSERVATION WELL X PUMPING WELL

WELL COLLAR HEIGHT ABOVE GROUND LEVEL 8.1 ft.

DEPTH TO STATIC WATER LEVEL 22.4 ft.

DATE AND TIME OF MEASUREMENT June 4, 1979 1212 hrs.

DATE	TIME (MINS)	DEPTH TO WATER (FT.)	DRAWDOWN (FT)	COMMENTS
June 4	1	22.4	0	
"	4	22.4	0	
"	7	22.3	+0.1	
"	23	20.2	+2.2	
"	32	19.6	+2.8	
"	40	19.0	+3.4	
"	58	18.0	+4.4	
"	98	16.5	+5.9	
"	120(2 hrs)	15.3	+7.1	
"	180(3 hrs)	13.6	+8.8	
"	240(4 hrs)	11.9	+10.5	
"	360(6 hrs)	9.4	+13.0	
"	480(8 hrs)	7.2	+15.2	
June 5	720(12 hrs)	4.6	+17.8	
"	960(16 hrs)	2.2	+20.2	
"	1080(18 hrs	1.2	+21.2	
"	1200(20 hrs	0.1	+22.1	closed valve

LOCATION BX IN SITU OIL SHALE PROJECT

WELL # BX - 30

OBSERVATION WELL X PUMPING WELL

WELL COLLAR HEIGHT ABOVE GROUND LEVEL 6.4 ft.

DEPTH TO STATIC WATER LEVEL 18.7 ft.

DATE AND TIME OF MEASUREMENT June 4, 1979 1220 hrs.

DATE	TIME (MINS)	DEPTH TO WATER (FT.)	DRAWDOWN (FT)	COMMENTS
June 4	2	18.2	+0.5	
"	4	17.5	+1.2	
"	6	16.5	+2.2	
"	12	14.3	+4.4	
"	23	11.4	+7.3	
"	35	9.4	+9.3	
"	46	7.9	+10.8	
"	61	6.4	+12.3	
"	90	4.1	+14.6	
"	120 (2 hrs)	1.3	+17.4	
"	180 (3 hrs)	0.3	+18.4	closed valve

LOCATION BX IN SITU OIL SHALE PROJECT

WELL # BX - 31

OBSERVATION WELL X PUMPING WELL

WELL COLLAR HEIGHT ABOVE GROUND LEVEL 6.3 ft.

DEPTH TO STATIC WATER LEVEL 17.0 ft.

DATE AND TIME OF MEASUREMENT June 4, 1979 1216 hrs.

DATE	TIME (MINS)	DEPTH TO WATER (FT.)	DRAWDOWN (FT)	COMMENTS
June 4	1	17.0	0	
"	3	16.8	+0.2	
"	5	16.5	+0.5	
"	8	16.0	+1.0	
"	11	15.4	+1.6	
"	22	13.8	+3.2	
"	33	12.6	+4.4	
"	44	11.7	+5.3	
"	60	10.9	+6.1	
"	90	9.4	+7.6	
"	120(2 hrs.)	8.0	+9.0	
"	180(3 hrs)	6.2	+10.8	
"	240(4 hrs)	4.5	+12.5	
"	360(6 hrs)	2.5	+14.5	
"	480(8 hrs)	2.5	+14.5*	closed valve

* Overflow to blowdown line noticed after 8 hours.

LOCATION BX IN SITU OIL SHALE PROJECT

WELL # BX - 32

OBSERVATION WELL X PUMPING WELL

WELL COLLAR HEIGHT ABOVE GROUND LEVEL 8.6 ft.

DEPTH TO STATIC WATER LEVEL 21.1 ft.

DATE AND TIME OF MEASUREMENT June 4, 1979 1230 hrs.

DATE	TIME (MINS)	DEPTH TO WATER (FT.)	DRAWDOWN (FT)	COMMENTS
June 4	3	21.1	0	
"	8	20.6	+0.5	
"	18	19.6	+1.5	
"	25	18.8	+2.3	
"	32	17.9	+3.2	
"	38	17.4	+3.7	
"	101	14.1	+7.0	
"	120 (2 hrs	12.9	+8.2	
"	180(3 hrs)	11.2	+9.9	
"	240(4 hrs)	9.4	+11.7	
"	360(6 hrs)	6.9	+14.2	
"	480(8 hrs)	4.8	+16.3	
June 5	720(12 hrs)	1.9	+19.2	
"	960(16 hrs)	0	+21.1	closed valve

LOCATION BX IN SITU OIL SHALE PROJECT

WELL # BX - 33

OBSERVATION WELL X PUMPING WELL

WELL COLLAR HEIGHT ABOVE GROUND LEVEL 8.3 ft.

DEPTH TO STATIC WATER LEVEL 21.5 ft.

DATE AND TIME OF MEASUREMENT June 4. 1979 1230 hrs.

DATE	TIME (MINS)	DEPTH TO WATER (FT.)	DRAWDOWN (FT)	COMMENTS
June 4	7	20.9	+0.6	
"	11	20.1	+1.4	
"	20	19.0	+2.5	
"	22	18.6	+2.9	
"	30	18.1	+3.4	
"	36	17.8	+3.7	
"	96	15.3	+6.2	
"	120(2 hrs)	14.2	+7.3	
"	180(3 hrs)	12.7	+8.8	
"	240(4 hrs)	11.1	+9.2	
"	360(6 hrs)	8.9	+11.4	
"	480(8 hrs)	7.1	+14.4	
June 5	720(12 hrs	3.8	+17.7	
"	960(16 hrs	1.7	+19.8	
"	1080(18 hrs	0.8	+20.7	closed valve

APPENDIX "B"

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APPENDIX "B"
BX IN SITU OIL SHALE PROJECT
TEMPERATURE LOG & SPINNER SURVEYS
JUNE 24-28, 1979

	RUN	DATE		REMARKS
BX-16	#1	6-24-79	Ran DTL while injecting water at 275°F. and 500psi.	2.5°F./100' heat loss in tubing. Deepest injection 865'. No injection into lower zone.
	#2	6-25-79	Ran DTL after 18 hour steam injection.	All injection into upper perforations. Maximum temp. 223°F. Normal temperatue gradient below 1000'.
BX-17	#1	6-25-79	Ran DTL while injecting 279°F. water at 500psi and rate of 450 BWPD.	3°F./100' heat loss in tubing. Deepest injection 1335 feet.
	#2	6-26-79	Ran DTL after steam injection for 13 hours.	Both upper and lower zone taking fluid. Temp. of upper zone 218°F. Temp. of lower zone 238°F. Zone between 500' and 600' shows a 25° reduction in temp. from the static temp.gradient. A review of the cement bond log shows very little cement across the zone, therefore the aquifer here is affecting the static temp.
	#3	6-28-79	Ran DTL after 72 hrs. steam injection.	Maximum temp. of upper zone 184°F. Maximum temp. of lower zone 238°F.

	RUN	DATE		REMARKS
BX-23	#1	6-27-79	Ran DTL after 18 hr. steam injection.	Injection into both zones. Maximum temp. in upper zone 221°F. Maximum temp. in lower zone 213°F. Deepest injection internal 1340 feet.
BX-24	#1	6-27-79	Ran DTL after 17 hrs. steam injection.	Injection into both upper & lower zones. Maximum temp. upper zone 214°F. Maximum temp. lower zone 228°F. Lower zone could be channeling up to 1000 feet. Bottom injection internal is 1330 feet. A temp. anonoly occurs between 480' and 530' because of affects of 4½" liner top.
BX-30	#1	6-24-79	Ran DTL while injecting 287°F. water at 500psi. Rate 450 BWPD.	2.5°F/100' grad. heat loss in tubing temp. at the bottom of upper zone 257°F. Temp. at the top of lower zone 135°. Upper zone was taking the most fluid.
	#2	6-25-79	Ran DTL after steam injection for 14hrs.	Upper zone has taken most of the injection. Maximum temp. of upper zone was 240°F. Maximum temp. of lower zone 130°.
	#3	6-28-79	Ran DTL after 72 hrs. steam injection.	Confirmed Run #2.
	#4	6-28-79	Ran DTL while injecting 70° water at a rate of 1440 BPD.	All injection was into the upper set of perforations.

	RUN	DATE		REMARKS
BX-30	#5	6-28-79	Ran continuous flow survey while injecting 942 BWPD 2 3/8" tubing.	Interval 816-840 taking 173.5 BWPD. " 850-860 " 768.5 ". No injection below 860'.
				CONCLUSIONS
BX-31	#1	6-24-79	Injection at 500psi & 290°F. Ran DTL.	4°F./100' heat loss in tubing 5°F./ 100' heat loss in casing 1305' deepest point of injection.
	#2	6-25-79	Steam injection for 24 hrs. Ran DTL.	Shows injection into both upper and lower perforations.
				REMARKS
BX-32	#1	6-26-79	Ran DTL while injecting hot water. Flow through control valve at manifold erratic causing temp. log to vary.	Deepest interval taking fluid was 1326 feet.
	#2	6-2[illegible]9	Ran DTL after well steam injection for 13 hrs.	Maximum temp. upper zone 202°F. Maximum temp. lower zone 204°F. Both intervals taking fluid.
	#3	6-26-79	Ran continuous flow survey (spinner log). Injecting 1050 BWPD down 2 3/8" tubing.	Interval 780-822 taking 420 BPD. Interval 835-858 taking 458 BPD. Interval 1254-1340 taking 171 BPD.
BX-33	#1	6-27-79	Ran DTL while injecting 270°F. water at 500psi.	Flow into both upper & lower perforations. Btm. most injection at 1320'.

	RUN	DATE		REMARKS
	#2	6-28-79	Ran DTL after steam injection for 13 hrs.	Maximum temp. upper perforations 224°F. Maximum temp. lower perforations 180°F. Deepest interval taking water 1306'.
BX-33	#3	6-27-79	Ran continuous flow survey (spinner log) while injecting 919 BWPD down 2 3/8" tubing.	Internal 800'-840 taking 450.5 BWPD. Internal 1270-1325 taking 468.5 BWPD.

APPENDIX "C"

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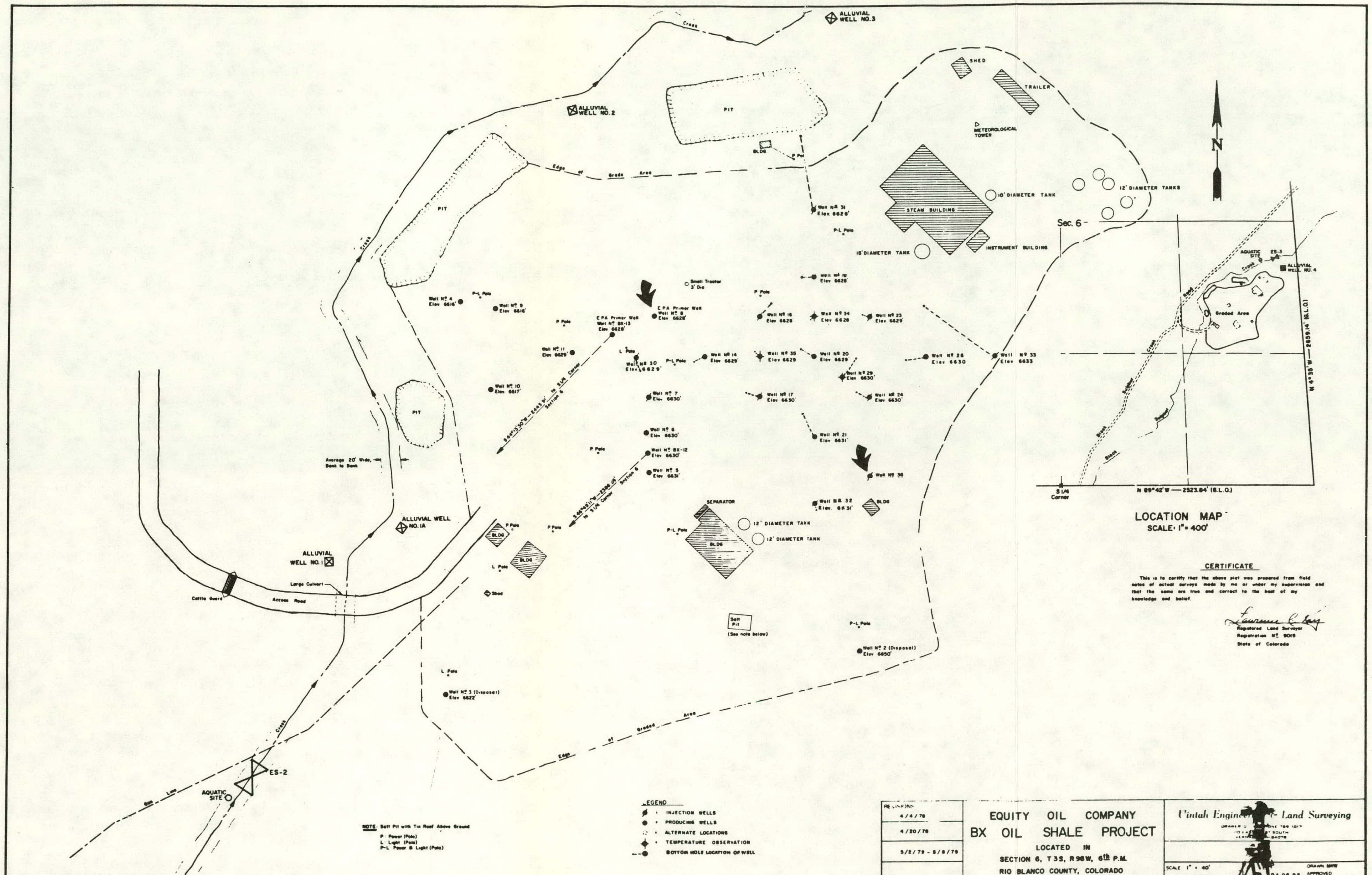

ALLUVIAL WELL NO.3
ALLUVIAL WELL NO.2
ALLUVIAL WELL NO. 1A
ALLUVIAL WELL NO. 1
Creek
PIT
SHED
TRAILER
METEOROLOGICAL TOWER
STEAM BUILDING
INSTRUMENT BUILDING
10' DIAMETER TANK
12' DIAMETER TANKS
15' DIAMETER TANK
Edge of Grade Area
N
Sec. 6
E.P.A. Primer Well
Small Tractor 3' Dia.
SEPARATOR
12' DIAMETER TANK
BLDG
Large Culvert
Cattle Guard
Access Road
Average 20' Wide, Bank to Bank
Salt Pit (See note below)
Well No. 2 (Disposal) Elev 6650'
Well No. 3 (Disposal) Elev 6622'
Edge of Graded Area
ES-2
AQUATIC SITE
ES-3
ALLUVIAL WELL NO. 4
Graded Area
S 1/4 Corner
N 89°42' W — 2523.64' (G.L.O.)
LOCATION MAP
SCALE: 1" = 400'
CERTIFICATE
This is to certify that the above plat was prepared from field notes of actual surveys made by me or under my supervision and that the same are true and correct to the best of my knowledge and belief.
Registered Land Surveyor
State of Colorado
NOTE: Salt Pit with Tin Roof Above Ground
P - Power (Pole)
L - Light (Pole)
P-L Power & Light (Pole)
LEGEND
INJECTION WELLS
PRODUCING WELLS
ALTERNATE LOCATIONS
TEMPERATURE OBSERVATION
BOTTOM HOLE LOCATION OF WELL
EQUITY OIL COMPANY
BX OIL SHALE PROJECT
LOCATED IN
SECTION 6, T3S, R98W, 6th P.M.
RIO BLANCO COUNTY, COLORADO
Uintah Engineering & Land Surveying

Appendix "C"

APPENDIX "D"

UTEC ME 80-042

YEARLY REPORT ON LABORATORY MODELING OF SUPER-HEATED STEAM RETORTING OF IN-SITU OIL SHALE

For the Period

1 March 1979 - 29 February 1980

by

Harold R. Jacobs
Martin J. Marzinelli
Kent S. Udell
University of Utah
Salt Lake City, Utah

Part I

RETORTING EXPERIMENTS

ABSTRACT

A series of experiments utilizing a six inch diameter (15.24 cm), sixteen foot long (4.877 m) retort were conducted to evaluate the processing of oil shale from the leached zone of the Parachute Creek formation by heating the shale with superheated steam. Steam at temperatures of up to 1000°F (537.8°C) and pressures up to 600 psig (4.137 MPa) was utilized in experiments lasting up to 117 hours, with most experiments being of a twenty-four hour duration.

The oil produced from these experiments showed a lower carbon/hydrogen (C/H) ratio than oil produced by combustion retorting or by Radio Frequency (RF) heating. For example, shale oil produced by Marathon Oil had a C/H = 7.48, oil produced at the University of Utah in a bottom burning combustion retort had a C/H = 7.08 and the RF heating produced oil of IITRI had a C/H = 6.95. The oil produced by superheated steam heating varied in C/H from 7.04 to 6.51. The lower C/H ratio oil produced in the present experiments had a longer residence time in the retort. The low C/H ratio oil also had a lower pour point. It is believed that these improvements are due to thermal refluxing in the retort.

INTRODUCTION

The "leached" zone of the Parachute Creek member of the Green River Formation in the Piceance Creek basin of northwestern Colorado has three unique characteristics which make it and other similar oil shale sections feasible targets for the in situ recovery of oil from oil shale.

The zone is:

Permeable and porous.

A very large saline water aquifer.

Composed primarily of very rich shale.

(Per acre reserves in excess of 1,000,000 barrels.)

The Equity Oil Company has investigated the potential for in situ recovery of oil from oil shale in this zone in the laboratory and the field since 1961. This work has shown that in situ recovery of oil shale by the injection of heated natural gas or steam is possible and that the oil produced is of a quality superior to that produced in conventional surface retorts.

This past field work developed data which indicated that the economic operation of a project using superheated steam as the injection fluid should be possible. Based on this work a Cooperative Agreement was reached between Equity Oil Company and the U.S.D.O.E. to jointly fund the BX In-Situ Oil Shale Project. This project encompasses both laboratory research and a field demonstration.

The laboratory work was subcontracted to the University of Utah. The laboratory work has as its goals verification of field operating parameters, characterization of products as a function of the parameters, and an attempt to understand the role of the operating parameters in the production of a high quality product.

EXPERIMENTAL APPARATUS

The major components of the experimental apparatus are shown in the flow diagram of Figure 1 and the photographs of Figures 2 and 3. This system was designed to investigate the retorting of oil shale with steam, and to collect and analyze the experimental by-products as a simulation of a commercial in situ operation. The important parameters of the experiment includes: steam flow rate, steam properties (temperature and pressure), the time temperature history of the shale, the properties of the shale and the by-products produced.

The experimental apparatus begins with the filtration and softening of the boiler feed water. A positive displacement pump ensures the proper water levels for the boiler. The 90 KW electric steam boiler produces steam at saturated conditions up to a maximum operating pressure of 600 psig (4.137 MPa). Upon exiting the boiler, the steam flows through a check valve. This check valve ensures that a reverse steam flow does not occur during intermittent boiler inactivity.

The saturated steam then flows through an orifice plate before entering the superheater. The orifice plate combined with a differential pressure transducer and an analog computer provides both instantaneous and total accumulated flow rates for specified static steam pressure and temperature.

The superheater is the last component of the system to alter steam properties before it enters the retort vessel. The 28 KW electric steam superheater has the capacity to raise 250 lbs/hr (113.38 kg/hr) of steam at 600 psig (4.137 MPa) to 1000°F (537.8°C).

Upon leaving the superheater the steam may enter the retort vessel or it can be diverted to the steam by-pass line. The retort vessel consists of four 48" (1.22m) long, 6" (15.24 cm) inside diameter flanged pipe sections. Any number of sections may be used, therefore experimental test lengths of 4', 8', 12' or 16' are possible (1.22 m, 2.44 m, 3.66 m, 4.88 m). Aproximately 50 lbs (22.67 kg) of shale can be contained in one vessel section. To obtain time-temperature histories and gas analysis information vital to the understanding of the chemical kinetics occuring in the shale, each retort section is equipped with four gas sampling ports and eight thermocouple ports. The thermocouples used are grounded chromel-alumel and the output is recorded on a 50 channel Fluke 2240 B datalogger.

Chemical gas analysis equipment was utilized to aid in the description of the chemical processes occuring during the pyrolysis of the organic material in the shale. The on-line gas sampling instrumentation for the retort is composed of two gas chromatographs incorporating three detector systems. The first gas chromatograph contains two thermal conductivity detectors which analyze for different "permanent" gases. The first detector looks for CO_2, and H_2S while the second detector analyzes for H_2 and the lighter gases eluted together. The second chromatograph utilizes a flame ionization detector to measure hydrocarbon gas percentages. A special timer and valve sequencing system allows known steam volumes from different retort locations to enter a small condenser unit. After condensation occurs, the liquid oil and water mixture is collected and the gases are routed to the chromatographs. Information from the chromatographs is sent to a central computer which stores and reduces the chemistry data.

The flow rate of steam is controlled by two pneumatic actuated, air-to-open, Valtex Mark I valves. The valves are located just before the superheater and immediately after the retort vessel to maintain proper flow conditions in various locations of the experimental apparatus.

The ability to reach high enough temperatures to drive the organic matter from the shale at relatively low flow-rates is essential. For that reason, all piping from the boiler to the retort vessel, and the vessel itself are insulated to reduce heat losses. The piping was covered with a 1200°F (648.8°C) mineral base insulation. The retort vessel uses two different insulations: a 1" (2.54 cm) layer of 1200°F (648.8°C) Fiberfrax ceramic fiber insulator is used next to the metal surface, and then a 2" (5.08 cm) layer of high temperature glass wool insulation is placed over the Fiberfrax.

The steam and chemical products exiting the retorts are throttled down to atmospheric pressure by the Valtek valve. The retort steam-product stream flows into the condenser which condenses the vapor and less volatile products. A liquid collection tank is located on the exit end of the condenser to collect the condensed oil and water. When testing is completed, the retort Valtek valve is closed and steam is diverted to the by-pass line to flush out any remaining oil which may have collected in the condenser.

Shale oil is sometimes present in both liquid and aerosol form after cooling. A mist eliminator system is needed to remove the aerosol from the retort off-gas. A method using tightly packed steel wool was developed and found to be effective in removing the aerosol.

The oil shale retort off-gas contains combustible gases and characteristically has an unpleasant odor. Hence, it is necessary to burn the retort off-gas under a flare hood and vent the exhaust from the laboratory. This is done after first analyzing the gases using the gas chromatographs and metering the total gas flow using positive displacement gas meters.

EXPERIMENTAL PROCEDURE

The twelve major retort experiments used shale from three different locations in order to characterize any relationship between retort by-products and shale origin. In the early experiments, Rifle, Colorado shale was screened and sorted in order to obtain pieces which would fit through a 3/4 in. (1.9 cm) screen and not a 5/8 in. (1.6 cm) screen for the experiments. The other shales were from the BX-12 and BX-13 field sites in Rio Blanco County, Colorado. This shale was obtained in 4 in. (10.2 cm) diameter cores which were later crushed to various sizes. Due to the varying nature of the Fisher Assay tests for these shales, average values for 100 percent Fisher Assay oil yield per section of retort were calculated.

The desired shale was then carefully hand packed into a section of the retort vessel. Thermocouples were inserted into desired locations along the length of the retort section in order to read centerline gas temperatures within the vessel. Upon completion of the packing, screens were fitted into the ends of the retort section to maintain the integrity of the shale structure within that particular section. That same procedure was followed for each of the vessels used, whether shale or another material (gravel, sand, or glass wool) was used for packing. Before bolting together the different vessel sections, a percentage void fraction for each section was obtained. In the later experiments, a baffling system composed of 80% baffles (20% open cross-sectional area) was installed in each section of the retort to increase the length of the flow path and therefore the residence time of the steam. The baffling system located baffles every 6 in. (15.24 cm) along the length of a vessel section starting half-way between the first and second thermocouple of each section. The open area of the baffles was alternated from top to bottom along the length of the retort. When the flanges of the retort sections were bolted together the experiment was ready to begin.

At the start of the experiment, the retort Valtek valve is closed and the two valves immediately before the superheater and the by-pass line valve is opened (Figure 1). The flow-metering system is now calibrated. To minimize the effect of unwanted preheating, the retort was filled with water. In two of the experiments, the shale was allowed to soak for several days in water from the field site. Water is then allowed to enter the boiler and the boiler is turned on. When steam begins to flow through the superheater, the superheater is switched on. The steam, which is now being superheated, is flowing through the by-pass line on to the condenser and liquid by-products tank. The datalogger which monitors and prints out temperature data is programmed.

When the steam reaches desired conditions the Valtek valve is opened allowing the steam to flow into and through the retort. During the test, temperatures and gas samples are taken automatically at specific predetermined times. When the shale temperatures reach a steady state for a desired length of time, the experiment is finished. The oil which is collected in the liquid by-products tank is separated from the water and dried. After drying the oil, experiments are conducted according to standard test procedures to determine pour point and API gravity. The oil is refrigerated at 12.2°F (-11°C) until its chemistry can be evaluated.

RESULTS

The twelve retort experiments were operated under a variety of conditions in order to evaluate the relationships between operating characteristics and the quality of the by-products produced. Several of the experimental parameters investigated were: shale size, shale origin, steam pressure and flow rate, maximum shale temperatures reached, porosity (void fraction), duration of the experiments, initial soaking of the shale in water from the field site, and residence time of the oil in the retort. A listing of the experiments and their characteristics is given in Table 1. Of the several parameters studied, the two which most affected the quality and quantity of the products produced from the shales of similar organic content were: maximum temperature the shale reached, and the residence time of the oil within the retort.

The effect of shale temperature on the amount of oil produced is directly related to the weight loss experienced by the shale. From an examination of Retort 11, as indicated n Table 1, it is apparent that as the shale temperature is increased the weight loss and therefore the oil produced is increased.

The relative effect of organic content on the quantity of oil produced can be seen in the weight loss data of the second shale sections of Retorts 10 and 11. Over a similar range of temperatures, the weight losses for Retorts 10 and 11 were 6.8% and 12.8% respectively. This significant change was caused by the substantial difference in the original Fisher Assays of shale from Retorts 10 and 11; 21.7 gal/ton (90.6 ℓ/tonne) and 27.06 gal/ ton (112.9 ℓ/tonne) respectively.

Table 2 indicates the characteristics of the products from each of the experiments. The earlier experiments, Retorts 2-7, yielded relatively high pour point oils, between 65°F (18.3°C) and 71°F (21.7°C) with an average of 68°F (20.0°C). These same experiments also yielded oils with the highest C/H ratio, with an average value of 6.92. The lowest C/H ratio was for Retort 2, the shale of which had received prior heating in Retort 1 before being produced. Comparison of pour point and C/H ratios for these retort experiments with the maximum average temperatures seen by the shale indicates that the variation in temperature alone does not strongly influence these characteristics. There also does not seem to be a strong dependence on relative shale size as Retort 5 yielded as high a fraction of Fisher Assay produced as the other experiments with considerably smaller pieces.

The effect of time-temperature relationships in the production of oil can be seen by comparing Retorts 7 and 8 with the prior experiments. The average peak temperatures in both Retorts 7 and 8 were considerably lower than the prior experiments, although exposure times were three or more times as large. These experiments produced the lowest fraction of Fisher Assay. Thus, production of oil is more a function of peak temperature than of exposure time.

Retort 8 included a section of glass wool following the shale. This provided an increased surface area on which the produced oil heavy ends could condense. As compared to Retort 7, the pour point was considerably reduced being 58°F (14.4°C) as compared to 71°F (21.7°C). The larger surface, in effect increases the residence time for the less volatile products. Consistent with the reduced pour point is a reduced C/H ratio as can be seen in Table 2.

In order to further investigate the effects of temperature and residence time of the less volatile products, Retorts 9, 10, 11 and 12 were performed. Retort 9 contained one section of glass wool and the entire vessel utilized 80% baffles as discussed in the procedures section. The result of adding the baffling system was to lower the oil pour point 7°F (3.9°C) less than Retort 8 while maintaining a similar C/H ratio.

The individual effect of a baffling system was investigated in Retort 12 by baffling the two shale sections and leaving the last two retort sections empty. An oil with a pour point of 41°F (5°C) was produced which had a C/H ratio of 6.57. The residence time of the oil was increased significantly in Retorts 10 and 11 by having two sections of glass wool behind the shale and by baffling the entire retort. The consequence of this increased residence time was a dramatic reduction in pour point temperatures and low values for C/H ratios. The pour points of Retorts 10 and 11 were 27°F (-2.8°C) with respective C/H ratios of 6.80 and 6.51. A reduction in percentage of Fisher Assay may occur when oils of a "lighter" quality are produced. This statement is qualified since, when a lighter and lower pour point oil is produced, collection is more difficult. It is believed that the reported values of percentage Fisher Assay are very conservative and that actual values should be higher. TGA tests currently being conducted on spent shale from the retort indicate that substantial amounts of oil are left in the shale which had not reached 700°F (371°C).

Further evidence of a lighter oil being produced when residence time is increased is the distillation results shown in Table 3 for Retorts 4 and 11. For comparison purposes distillation data are also shown for dielectric heating produced shale oil, combustion produced shale oil, in situ retorting with methane (Hill and Dougan) and light Arabian Crude. The results indicated in Table 3 show that Retort 11, of the steam injection process, contains a significantly larger percentage of light distillates (600°F (316°C) or less) when compared to the other processes. The retorting processes which most closely compare to Retort 11 are the Bottom Burn Combustion Retort and the methane injection in situ process of Hill and Dougan.

Additional comparisons are made with other oils in Table 4 which presents C, H, N, O, S compositions, pour points etc. The lowest C/H ratio was again for Retort 11. Differences observed in the "Bottom Burning Retort" oil and the oil from the present experiments indicates that the products are not identical as there exists a significant difference in pour point and elemental composition. These differences may be associated with the extreme temperatures, ~ 1800°F (1000°C) seen in a combustion retort and presence of molecular oxygen in the heating medium. It is planned to carry out additional chemical characterization in order to deduce these differences.

CONCLUSIONS

Several factors indicate that the high percentage of light distillates produced in Retort 11 (92%) are a consequence of an increase in the residence time of the oil in the retort. This idea was brought out dramatically in Retorts 8 through 12 where the flow path was lengthened by a baffling system, and a large surface collection area (glass wool packing) for the oil was utilized. Those two procedures caused the oil to remain within the high temperature environment of the retort for increased lengths of time. The increased residence time results in the thermal cracking of the heavy ends. This point is indicated when one compares the results of Retorts 4 and 11 (Table 4). The larger residence time of Retort 11 leads to a substantially larger percentage of light distillates (92%) as compared to Retort 4 (59.4%) which had no glass wool packing or baffling.

Thermal cracking of a heavy oil results in oil having a lower pour point temperature, C/H ratio and specific gravity (high API gravity) value. The results for Retorts 4 and 11 show that significant reductions occur in all three of these oil properties. This general effect can be seen when the larger residence time experiments of Retorts 8 through 12 are compared to the first seven experiments (Table 3).

The process of thermal cracking or refluxing of oil has been shown to be the single most essential operating characteristic in producing large percentages of light distillates in a Bottom Burning Retort [1]. In that retorting process, the effect of oil condensation and then reheating of the oil was the mechanism for thermal cracking. A similar process of condensation and reheating is induced in the steam retort when glass wool packing and baffles are utilized. The proposed mechanism for production of shale oil by superheated steam injection thus includes the initial production of an oil similar to that of Retorts 2-7. The vapor stream would then transport the oil mixture through the porous shale bed until the heavy ends condense and precipitate out on to a cool shale surface. Then as the thermal energy wave propagates along the path through the shale, the condensed oil is once again subjected to high temperatures which causes revolitization and thermal cracking. The refluxing mechanism appears to be substantiated as the oil properties for Retort 11 and the Bottom Burning Retort are similar, even though the retorting processes are quite different.

In the leached zone of the Parachute Creek formation the permeability and porosity, although high, is much lower than could be obtained in the laboratory. Typically the path from superheated steam injection well to the production well is more tortuous and much longer (well placing is ~ 100 ft) (30.5 m)). It is thus expected that the oil produced in the field will resemble that of Retort 11. Preliminary data from back flowing an injection well has indicated that this will be true as indicated by the C/H data of Table 4. However, it is believed that this C/H ratio may be a bit low due to incomplete drying of the sample. It is hoped to obtain better field samples in the future to firm these conclusions.

REFERENCES

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[4] Dougan, P., "Development Proposal Submitted to the Energy Research and Development Administration - Oil Shale In Situ, Development and Project," Equity Oil Company, Salt Lake City, Utah, March, 1976.

[5] Snow, R. H., et al., "Comparison of Dielectric Heating and Pyrolysis of Eastern and Western Oil Shales," 12th Oil Shale Symposium, Colorado School of Mines, 1979.

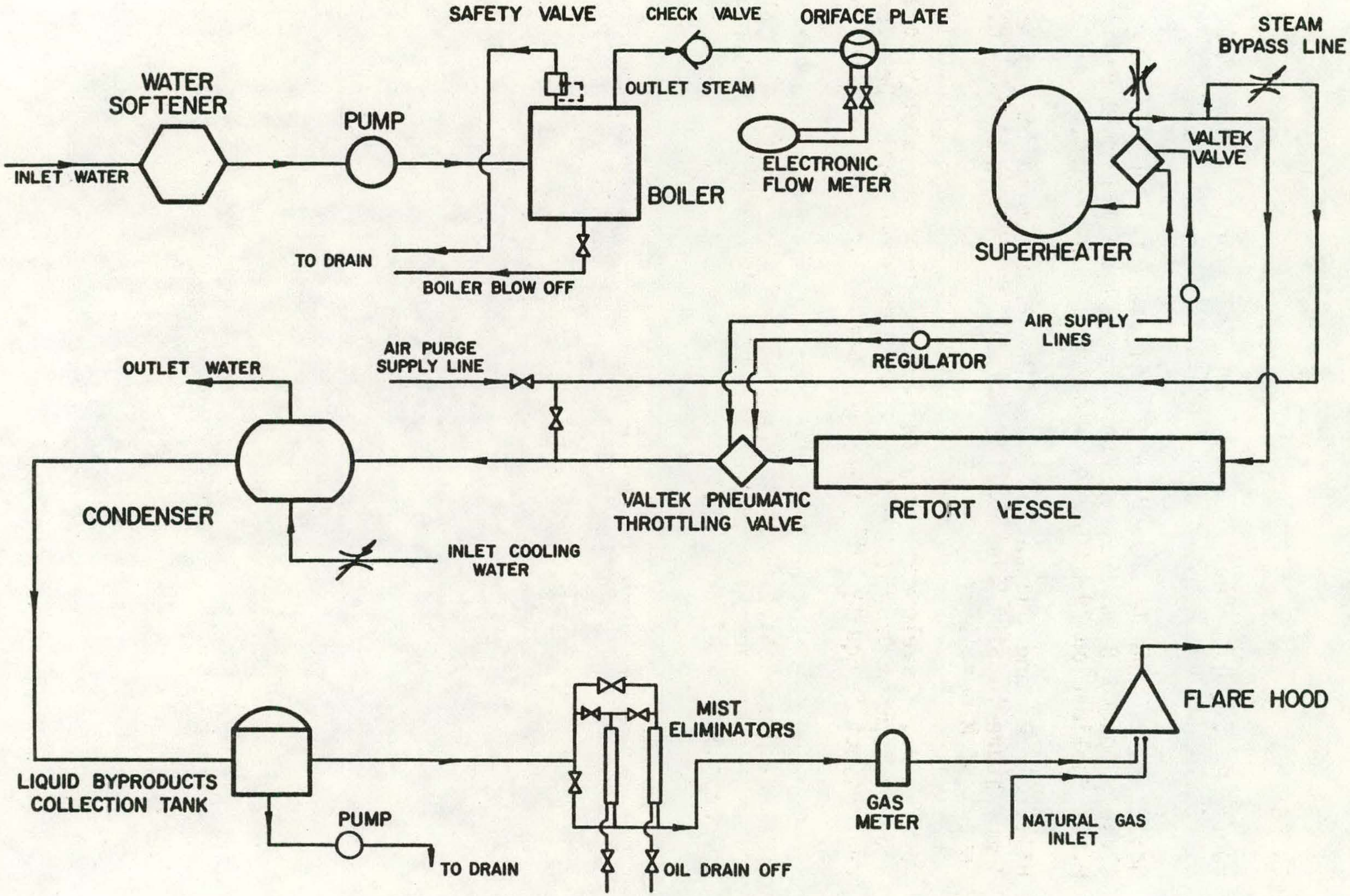

Figure 1: Flow Diagram of Steam Retorting Experimental Apparatus

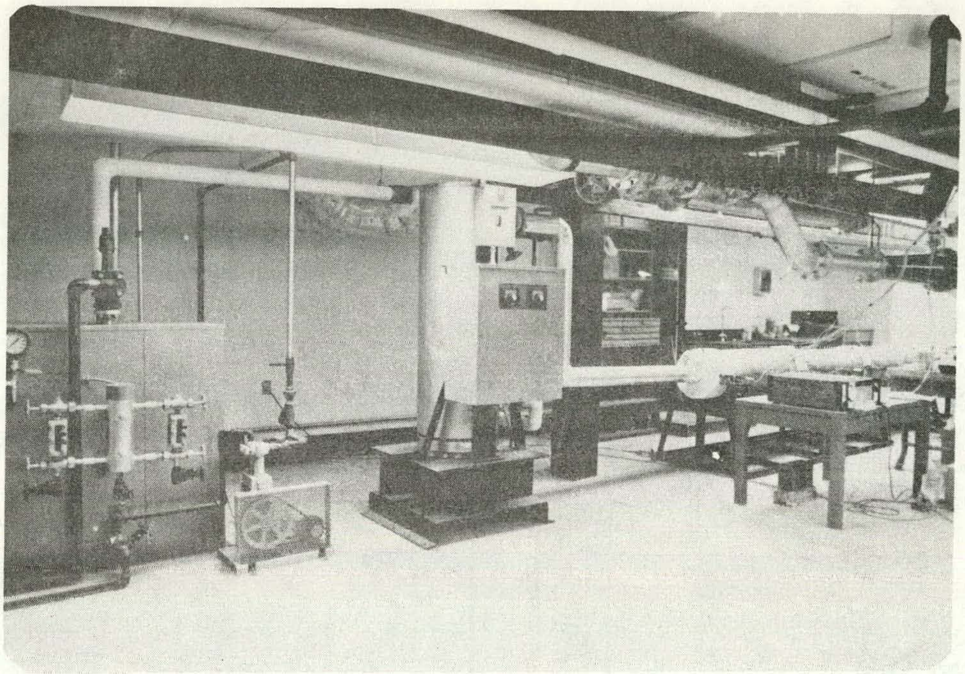

Figure 2. Photograph of Boiler, Positive Displacement Pump, Superheater and Retort Vessel (left to right)

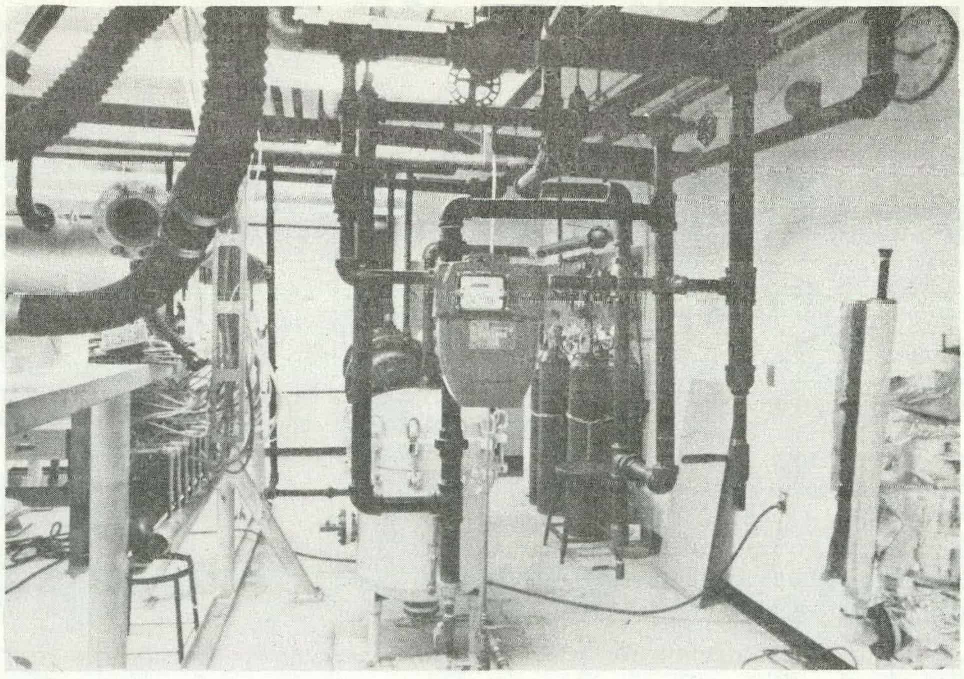

Figure 3. Photograph of Gas Flow Meter and Mist Eliminator Piping, Liquid By-Products Collection Tank and Condenser (foreground to background)

Table 1

RETORTS Equity Oil Experiments	DURATION(HR)	PRESSURE	AVERAGE FLOW RATE	CHARACTERISTICS (1) Origin (2) Fisher Assay (3) Size	VESSEL DATA (1) Material Used, Void Fraction (2) Original-Final Weights,% Change (3) Inlet-Outlet Max. Temperatures(°F)
1	3.33	250 PSIG 1.724 MPa	200 to 300 LBS/HR 91 to 136 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Gravel,N.A. Gravel,N.A. Shale,N.A. 78.5-78.5,0% 81.0-81.0,0% 77.0-77.0,0% 49.5-49.0,1% 754°-N.A. N.A.-N.A. N.A.-N.A. 529.7°-471.5°
2	6.17	270 PSIG 1.862 MPa	200 to 300 LBS/HR 91 to 136 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Gravel,N.A. Shale,N.A. 78.5-78.5,0% 77.0-77.0-0% 49.5-39.2,20.8% 1019°-N.A. N.A.-N.A. 860°-809° (Same Shale as First Experiment)
3	28.00	270 PSIG 1.862 MPa	40.1 LBS/HR 18.2 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,N.A. Shale,N.A. 78.5-78.5,0% 52-40,23% 50-49,2% 965°-N.A. 809°-724° 705°-643°
4	26.50	570 PSIG 3.930 MPa	51.9 LBS/HR 23.5 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale.N.A. Shale,N.A. 78-78,0% 54.0-42.5,21.7% 53-4[illegible],[illegible]4.8% 950°-N.A. 813°-741° 720°-663°
5	11.50	300 PSIG 2.068 MPa	78.1 LBS/HR 35.4 Kg/HR	Equity BX-12 L.A. Various Sizes	Gravel,N.A. Shale,40.8% Instrumented Shale Piece 78.5-78.5,0% 57.0-49.9,12.5% 967°-N.A. 868°-796° 794°
6	21.25	250 PSIG 1.725 MPa	68.6 LBS/HR 31.1 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,51.0% Shale,4[illegible]% Sand,37.0% 78.5-78.5,0% 57.1-45.3,20.7% 56.7-47.2,16.8% 76.0-74.5,2.0% 971°-N.A. 886°-833° 823°-771° 763°- 724°
7	117.25	320 PSIG 2.206 MPa	39.8 LBS/HR 18.0 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,47.3% Shale,48.4% 78.5-78.5,0% 52.2-42.6,18.4% 51.3-46.5,9.3% 868°-N.A. 732°-654° 652°-591°
8	101.00	300 PSIG 2.068 MPa	31.5 LBS/HR 12.6 Kg/HR	Equity BX-12 L.A. Various Sizes	Shale,46.5% Shale,50.6% Glass Wool, N.A. 56.0-50.1,10.5% 54.5-51.4,5.7% N.A. 761°-636° 621°-565° 560°-539°
9	17.00	250 PSIG 1.724 MPa	67.8 LBS/HR 30.7 Kg/HR	Equity BX-12 L.A. Various Sizes	Shale,44.0% Shale,45.9% Glass Wool,90.8% 50.6-42.0,17.0% 51.5-45.5,11.6% N.A. 1006°-900° 881°-832° 820-785°
10	18.00	570 PSIG 3.930 MPa	50.5 LBS/HR 22.9 Kg/HR	Equity BX-12 L.A. Various Sizes	Shale, N.A. Shale,N.A. Glass Wool,N.A. Glass Wool, N.A. 54.5-44.2,18.9% 58.6-45.6,9.9% N.A. N.A. 900°-784° 761°-665° 634°-591° 473°-395°
11	24.00	270 PSIG 1.862 MPa	50.1 LBS/HR 22.7 Kg/HR	Equity BX-13 L.A. Various Sizes	Shale,45.4% Shale,47.4% Glass Wool, N.A. Glass Wool, N.A. 49.9-40.2,19.5% 55.2-48.1,12.8% N.A. N.A. 960°-N.A. 761°-666° 635°-410° N.A.-N.A.
12	21.00	270 PSIG 1.862 MPa	51.6 LBS/HR 23.4 Kg/HR	Equity BX-13 L.A. Various Sizes	Shale,N.A. Shale,N.A. Empty Empty 56.3- 47.2, 16.3% 60.2-51.3,15.1% 946°-917° 795°-714° 543°-537° 537°-536°

N.A. = Not Available
L.A. = List Avaiable
* = Estimated Value

Table 2

RETORTS Equity Oil Experiments	OIL DATA (1) Amount Produced,% Fisher Assay (2) Pour Point Temperature (3) API Gravity	Gases Produced	CHEMICAL ANALYSIS ON OIL C	H	N	O S (Wt %)	C/H
1	No oil produced	0					
2	N.A.,85% 70°F,(21.1°C) N.A.	60.0 c.f.	83	12.2	1.4	3.4*1	6.80
3	N.A. 65°F,(18.3°C) N.A.	55.0 c.f.	81.7	11.6	2.0	4.7*1	7.04
4	9.67Lbs(4.39Kg),85% 69°F,(20.6°C) 21.80	109.5 c.f.	83.8	12.1	1.9	2.2*1	6.93
5	6.08Lbs(2.76Kg),98.9% 67°F,(19.4°C) 26.95	N.A.	82.4	12.0	2.2	3.4*1	6.87
6	8.70Lbs(3.97Kg),69.5% 68°F,(20.0°C) 23.80	90.2 c.f.	83.4	12.0	1.6	3.0*1	6.95
7	6.07Lbs(2.75Kg),58.4% 71°F,(21.7°C) 26.60	N.A.	82.3	11.9	1.4	4.4*1	6.92
8	3.59Lbs(1.63Kg),34.6%* 58°F,(14.4°C) 25.40	N.A.	81.7	12.0	1.4	4.9*1	6.81
9	7.25Lbs(3.29Kg),98.0% 51°F,(10.6°C) 25.90	101.8 c.f.	82.4	11.9	1.9	3.8*1	6.92
10	5.10Lbs(2.31Kg),56.5% 27°F,(-2.78°C) 28.57	64.6 c.f.	82.9	12.2	1.7	3.2*1	6.80
11	5.76Lbs(2.61Kg),53.8% 27°F,(-2.78°C) 26.95	93.5 c.f.	84.6	13.0	1.4	0.9*1	6.51
12	4.51Lbs(2.05Kg),47.7% 41°F,(5.00°C) 26.60	85.4 c.f.	83.4	12.7	1.4	2.5*1	6.57

N.A. = Not Available
* = Estimated Value
1 = Combined O and S

Table 3

PROCESS	NAPTHA IBP to 400°F IBP to 204°C	LIGHT DISTILLATE 400°F to 600°F 204°C to 316°C	LIGHT GAS OIL 600°F to 800°F 316°C to 427°C	HEAVY GAS OIL 800°F to 1000°F 427°C to 538°C	RESIDUUM Over 1000°F Over 538°C
Steam Retort 11	33.7	58.3	6.1	1.9	0
Bottom Burning	40	45	4.6	1.8	8.6
Hill & Dougan	45	35	12	6	2
IITRI	45	23	6	26	-
Arabian Light	36	23	17	17	7
Steam Retort 4	13.7	45.7	40.1	0.5	0
Tosco	22	32	17	11	18
Garret	18	45	20	13	4
Paraho	8	44	20	19	9

Comparison of Distillation Properties From Various Retorting Processes. (Non-steam retorting data from references 1 and 5)

Table 4

RETORTS	OIL DATA (3) Amount Produced,% Fisher Assay (2) Pour Point Temperature (3) API Gravity	Gases Produced	CHEMICAL ANALYSIS ON OIL C	H	N	O	S (Wt %)	C/H
Steam Retort 11	5.76Lbs(2.61Kg),53.8% 27°F,(-2.78°C) 26.95	93.5 c.f.	84.6	13.0	1.4	0.9*1		6.51
Bottom Burning	N.A.,65% 68°F,(20.0°C) 31.70	N.A.	84.1	11.9	2.1	1.9*1		7.08
Hill & Dougan	N.A. -4°F,(-20.0°C) 40.00	N.A.	N.A.	N.A.	0.8	N.A.		N.A.
IITRI	N.A.,96% 40°F,(4.44°C) 34.40	N.A.	84.0	12.1	1.0	2.8	.6	6.94
Arabian Light	N.A. N.A. 34.40	N.A.	N.A.					N.A.
Steam Retort 4	9.67Lbs(4.39Kg),85% 69°F,(20.6°C) 21.80	109.5 c.f.	83.8	12.1	1.9	2.2*1		6.93
Tosco	N.A. 70°F,(21.1°C) 20.98	N.A.	N.A.					N.A.
Garret	N.A. 85°F,(29.4°C) 19.35	N.A.	N.A.					N.A.
Paraho	N.A. 50°F,(10.0°C) 25.03	N.A.	N.A.					N.A.
Marathon Oil Batch	N.A. 82°F,(27.8°C) 20.40	N.A.	84.0	11.2	1.7	1.6	.8	7.50
Continuous Flow	N.A. 74°F,(23.3°C) 21.10	N.A.	83.3	11.0	1.8	2.6	.8	7.57
Equity Field Site	N.A. N.A. N.A.	N.A.	74.8	12.0	0.6	12.6*1		6.23

N.A. = Not Available
* = Estimated Value
1 = Combined O and S

Part II

Autoclave Experiments

by

A. Lamont Tyler

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ABSTRACT

A series of tests were performed in the one-liter Autoclave reactor to determine the effect of steam on oil shale samples from the BX-12 and BX-13 cores, and the effect of steam in cracking of the shale oil liquids after they were produced.

The tests were designed to provide basic information concerning retorting utilizing steam at pressures up to and above those which could be attained in the Retort Experiments. The total recovery of the organic fraction of the oil shale increased linearly from 60% at 700 psi in steam to approximately 80% at 1300 psi and was essentially independent of the temperature over the range of temperatures employed (371°C to 454°C).

The steam induced cracking experiments show that both a reduction in the oil molecular weight and in the C/H ratio occur during exposure of the oil to steam at temperature between 371°C and 454°C. GC-MS and elemental analyses of the oil show an increase in hydrogenation during cracking and formation of principally normal alkanes in oil. Analyses of the gases released during steam induced cracking experiments substantiate the results of the oil analyses. Both sulfur and nitrogen content of the oil are reduced by steam cracking.

The initial autoclave experiments dealt with processing samples taken from the BX-12 and BX-13 cores in steam in the autoclave reactor. Cores which are 1½ inches (3.81 cm) in diameter and from 2½ to 3½ inches long (6.35 cm to 8.89 cm) have been cut with the bedding plane perpendicular to the axis of the cylindrical core. Samples were clamped to duplicate, as nearly as possible, the confined configuration which would be encountered underground.

Figure 1, contains data WHICH substantiates the observation that the overall weight loss varies essentially linearly with the steam pressure over a temperature range from 700°F to 800°F. (371°C to 426°C) The samples were all exposed to steam at the temperature and pressure indicated for times which varied from 18 to 21 hours. The time variations within this range does not appear to affect the total yield. This is consistent with observations in the Retort Experiments. While it has been observed in the steam retort runs that the decomposition of the inorganic carbonates to yield CO_2 proceeds rapidly in the presence of steam at temperatures below those normally associated with carbonate decomposition in inert gases, the same phenomenon has not been observed in the ~~retort~~ AUTOCLAVE runs. CO_2 concentrations have remained below approximately 20% (on a dry basis) in the gases envolved from the reactions. However, for a very rich sample (64 gal/ton) of oil shale, the measured organic yield from weight loss did not fall on the curve in Figure 1, but was well below the line drawn through the other points.

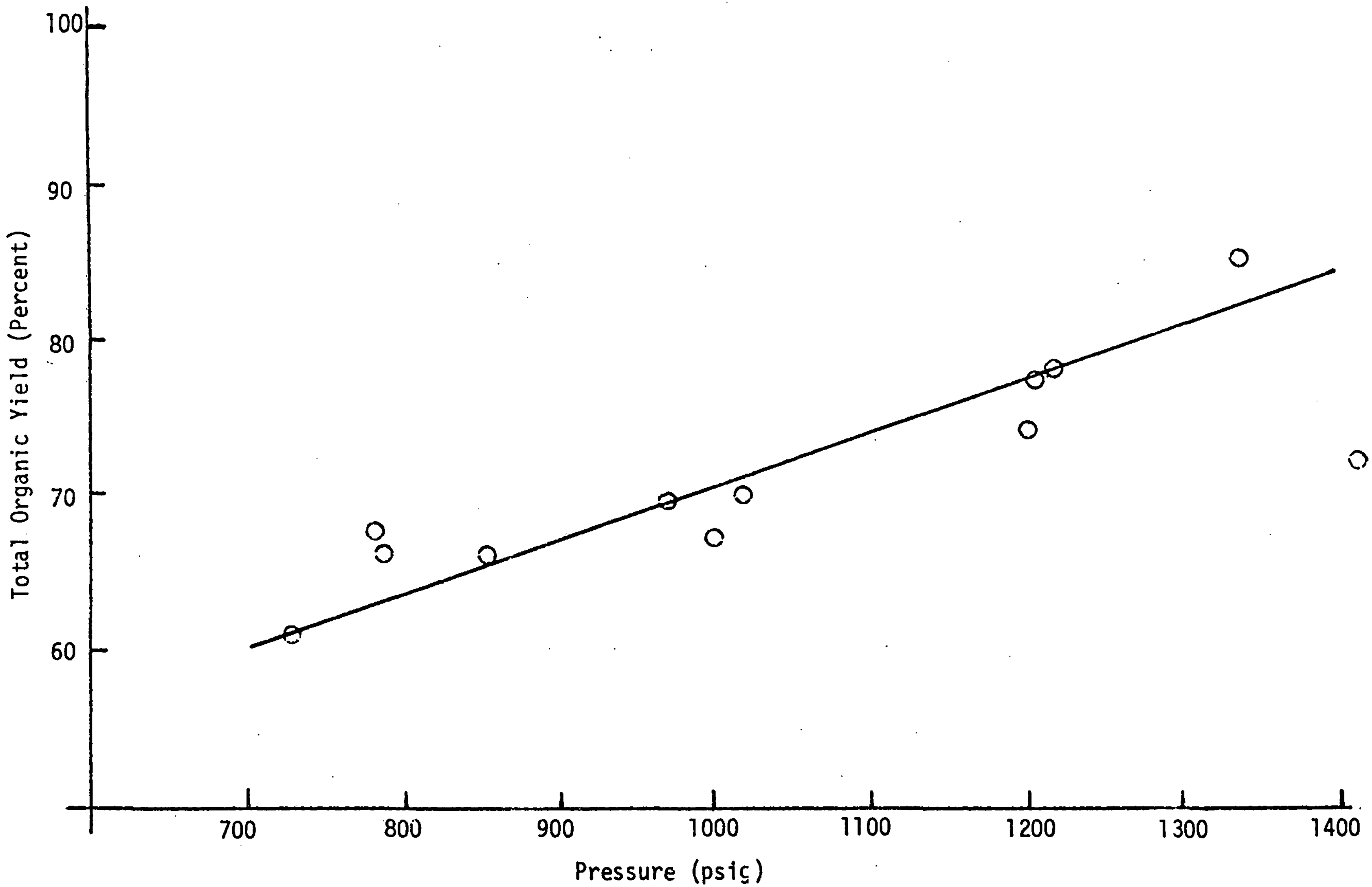

Figure 1: Effect of Steam Pressure on Total Organic Yield

II. Results of Gas Analyses

Gases evolved from the autoclave experiments are analyzed with a gas chromatograph to determine the concentrations of the important constituents. Water is removed before the analyses, and hydrogen IS determined in a separate measurement with an N_2 carrier. A typical analysis from gases evolved during 24 hours in steam in an autoclave are given in Table I.

Table I

Typical Autoclave Gas Composition
Steam Retorting Runs

	percent by weight	
Methane	47.5	
Ethene	0.1	
Ethane	21.6	
Propene	0	
Propane	8.5	
Butene	1.9	
Butane	1.5	
C_5 and above	0.4	
TOTAL HYDROCARBONS		81.5
Hydrogen	3.0	
Oxygen	0.3	
Nitrogen	2.7	
CO	3.1	
CO_2	6.6	
H_2S	7.3	
		104.5

The noteworthy aspects of the above analysis is the high hydrocarbon and H_2S concentrations and the low CO and CO_2 concentrations. The unsaturated hydrocarbons are very very low, which suggests that the olefins are hydrogenated by either steam or hydrogen produced from the water gas reaction. The low unsaturates suggest that retorting in high pressure steam offers a significant competitive advantage over retorting in air or inert gases.

III. Carbon, Hydrogen, and Nitrogen Analyses of Liquids

C, H, and N analyses of the liquids produced in the autoclave experiments have been completed. Results suggested that the oil was hydrogenated since the ratio of hydrogen to carbon in the oils is significantly higher than in the kerogen before retorting, and higher than in shale oil produced by retorting in inert atmospheres. The average H/C molar ratio of oil from three samples retorted in steam at temperatures from 700°F to 720°F was 1.76 -- approximately equal to that observed in petroleum crudes which contain essentially no unsaturated compounds. (This is equivalent to a C/H ratio of 6.8 on a mass basis.) The results are listed in Table II.

Table II

Liquid H/C Ratio

Sample No.	Temperature	H/C Molar Ratio in Liquid
12-937.5	370°C (698°F)	1.75
12-936.1	328°C (719.6°F)	1.79
12-936.3	431°C (807.8°F)	1.08
12-936.2	382°C (721.4°F)	1.74

At the elevated temperature (431°C, 808°F), the ratio of carbon to hydrogen was lower than for the other runs, but the equilibrium of the water gas shift reaction favors the formation of water rather than hydrogen at the higher temperature. At 370°C (698°F), the ratio of hydrogen to carbon was approximately 1.75 -- the ratio for typical petroleum crudes which usually contain no olefins and less than 10 percent aromatic compounds. The samples were prepared for NMR analyses to determine the ratio of olefinic to aliphatic hydrocarbons to see if the postulate that the oil was saturated was correct. Results of the NMR tests were obtained in July, 1979. The results indicated 80 percent saturated hydrocarbons with approximately 20 percent aromatics. Essentially no olefins were detected. The indication from these experiments is that steam is effective in hydrogenating oils at temperatures from 370°C to 430°C (700°F to 810°F). Oils so processed would be more valuable as a refinery crude feedstock since they would require no hydrogenation to prevent gum formation in gasoline and other motor fuels.

The nitrogen content in the autocalve-produced oil samples was in the range of 2.0 to 2.8 weight percent except for the sample 12-936-3 which was treated at the higher temperature. The nitrogen content of that sample was 4.8 weight percent. It is not known whether that data point was a result of the higher temperature treatment or caused by some other factor. The fact that it corresponds to the run with the low H/C molar ratio suggests that either the sample or the method of treatment is different.

A recent paper by AMOCO engineers[1] indicates that Oklahoma oil shale from the Woodford formation can be pyrolyzed in water at 330°C (626°F) to yield an oil free of olefins. This offers further con-

[1]Lewan, M. D., J. C. Winters, and J. H. McDonald, "Generation of Oil-Like Pyrolyzates froj Orgainic-Rich Shales," *Science, 203,* 897-899 (March, 1979).

firmation of the ability of water to hydrogenate shale oil. Thus, steam retorting processes have an important competitive advantage over straight pyrolysis methods. Based on this paper and our experiments described above, work was initiated in July 1979, on autoclave hydrogenation treatment of retort oil samples from Retorts 2 through 6.

Sampling equipment was designed and fabricated to extract and cool samples of both the liquid and gas phases during autoclave operation. During July, only two samples were run due to the necessity to work around the major retort experiments. During this time, analytical equipment was set up to determine the average molecular weight of the oil. During August, samples were run frequently (every 2 to 3 days). Tests were conducted for time up to 24 hours at temperatures from 287°C (550°F) to 454°C (850°F). Samples were taken at four-hour intervals during the run, and the production of hydrocarbon gases continued during the first 16 hours as indicated by a continuous increase in concentrations. For example, at 550°F the hydrocarbon concentration rose from 47 percent after four hours to 65 percent after 24 hours, and at 700°F from 50 percent after four hours to 85 percent after 24 hours. Hydrogen sulfide concentrations were unexpectedly high (6% and higher) during the first four hours after heating began. It was apparently produced early in the run and exhausted during sampling since measured concentrations decrease over the course of the run to less than one percent. Hydrogen concentrations from six to 10 percent were also measured after 24 hours and indicates that sufficient hydrogen is present to hydrogenate the oil upon cracking.

Typical gas concentrations for the cracking experiments are shown in Table III for the 700°F and 850°F runs; the differences are less than the uncertainty in the measurements in most cases.

Table III

Typical Gas Analysis

	700°F Run	850°F Run
Methane	27.4%	30.3%
Ethene	1.01	1.3
Ethane	19.6	16.2
Propene	0	0.01
Propane	14.6	12.4
Butene	2.7	2.5
Butane	5.5	4.0
Pentene	2.3	2.3
Pentane	3.2	3.1
C_6 and above	5.0	5.6
CO_2	5.4	7.6
H_2S	0.6	1.0
Hydrogen	4.7	7.7

Minimal cracking occurred during the 287°C (550°F) run as determined by visual examination of the resultant oil. However, at 371°C (700°F) the resultant oil was extremely fluid and the extent of cracking had been significant.

Attempts to determine the average values of the oil molecular weights have been made by measuring the melting point depression of a solution of the oil in camphor, by vapor-phase osmometry of a pyridine solution of the oil, and by GC-MS. The attempts to obtain the molecular weight by GC-MS techniques were frustrated because of the inability of the laboratory which made the measurements to reduce the data for a mixture containing such a large number of species. The results of the other two methods are shown in Table IV. The experimental procedures permit the measurement of the melting point depression within approximately 0.4°C which leads to an error of 10 in the average molecular weight. Reported molecular weights from Huffman Laboratories, Inc., using the vapor-phase osmometry procedure are 75 percent higher than measurements made in our laboratory by melting point depression techniques. The difference is significantly greater than can be attributed to uncertainty in either experimental procedure. The results show that the molecular weight does decrease during the cracking, but quantitative determination of the molecular weight remains uncertain.

Table IV

Average Molecular Weights

Sample	By Melting Point Depression Meas.	By Vapor-Phase Osmometry
Raw Shale Oil		
Retort Run 4	268	465
Retort Run 5	210	352
Retort Run 6	266	431
Cracked Shale Oil (Oil from Retort Run 4) (at 550°F)		
After 4 hours		
(Vapor Sample)	209	317
(Liquid Sample)	262	358
After 24 hours		
(Only one phase)	167	NA

C, H, and N Analyses

The elemental analyses to determine the weight fractions of carbon, hydrogen, and nitrogen have been much more successful than attempts to determine the average molecular weight. Measurements of these elements were made with the Perkin-Elmer 240B Elemental Analyzer on samples taken at various times during the cracking runs. Although data are still being obtained, the results available to date are shown in Table V.

Table V

Carbon, Hydrogen, and Nitrogen Analyses

	C	H	N	(O&S)	C/H
Oil from Retort 6 (Starting Material)	83.4	12.0	1.6	3.0	6.95
After Cracking at 700°F in steam					
8 hours	84.9	12.6	1.2	1.2	6.72
10 hours	84.3	12.6	1.1	1.7	6.66

These results substantiate that cracking and hydrogenation of the oil is occurring. The drop in the C/H ratio also suggests that the oil is more valuable for a refinery feed stock after cracking. The drop in the nitrogen content and in the sulfur and oxygen content (determined by difference) also suggest that the value of the oil is enhanced by steam cracking.

Figures 2 and 3 are typical gas chromatograms of the oils before and after cracking. Figure 2, the chromatogram of the raw retort oil, shows significant concentrations of species with molecular weights higher than that of C_{25} as well as substantial peaks of unsaturated

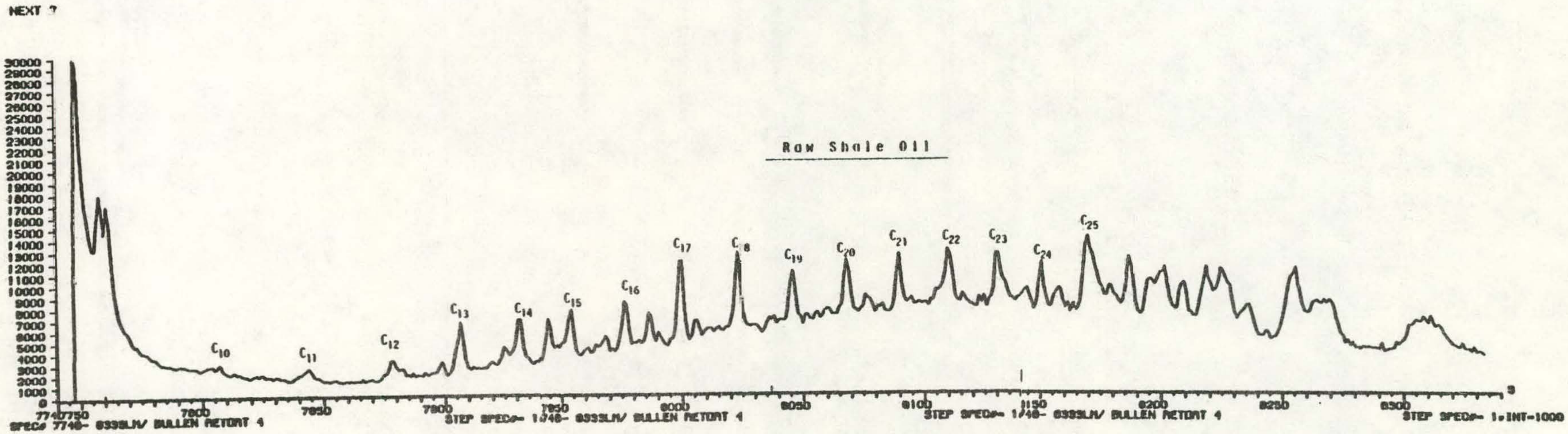

Figure 2 Raw Shale Oil Chromatogram

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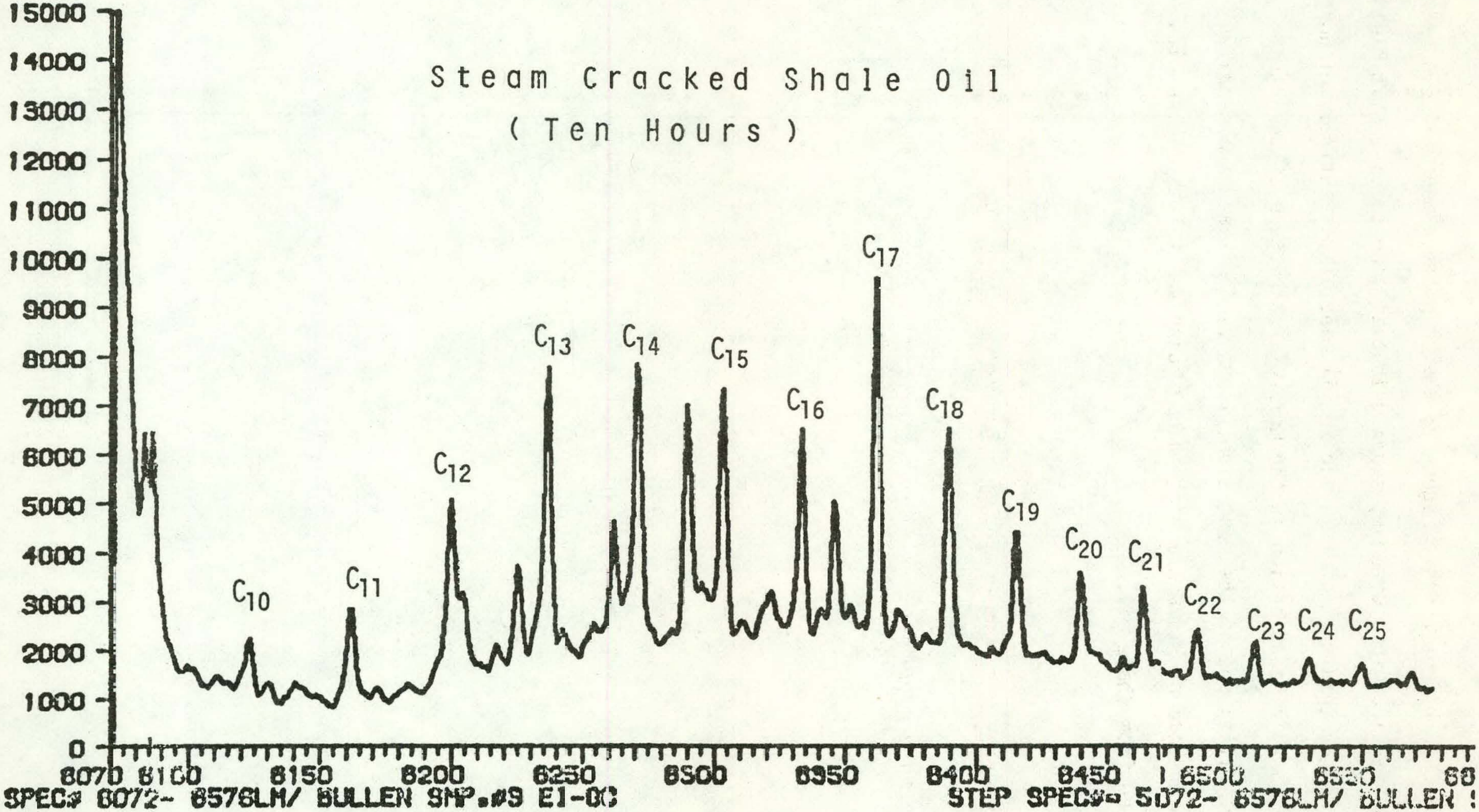

Figure 3 Cracked Oil Chromatogram

and branched hydrocarbons. Figure 3, the chromatogram of oil cracked at 700°F (371°C) for 10 hours, shows essentially no species with elution times longer than that of C_{25}, and an oil made almost entirely of normal alkanes. This modification in the molecular structure of the steam cracked oil is one of the most significant findings and demonstrates the importance of steam cracking in upgrading the values of the oils obtained from shale oil.

GAS COMPOSITIONS DURING CRACKING EXPERIMENTS

The composition of the gas phase during the cracking experiments has been measured by drawing periodic samples and determining the composition on a gas chromatograph. The gas composition as a function of time at temperatures of 550°F (255°C), 700°F (371°C) and 850°F (454°C) is shown in Figures 4, 5, and 6.

The significant results of the time dependence on the composition is that the hydrogen remains essentially constant in its mole fraction; the saturated and unsaturated hydrocarbons reach a steady value after eight to 10 hours and then remain unchanged; and the hydrogen sulfide has an initial high value and then drops sharply to a lower and constant value. The hydrogen sulfide, it is presumed, is rapidly generated as sulfur and is hydrogenated in the sulfur-containing compounds of the oil and is exhausted in the sampling procedure; thus, accounting for the apparent drop in its concentration. The constant value of the hydrogen concentration suggests that perhaps the system reached a quasi-equilibrium. The calculated equilibrium concentration was compared with the measured concentrations of specific hydrocarbons such as methane, ethane, and propane, but the predicted equilibrium occurs when nearly all of the hydrocarbons reach methane. The observed methane to ethane to propane ratio was approximately 2.5:1.25:1. It is concluded, therefore, that the gases are not close to the equilibrium concentrations and the cracking reactions are rate limited. The hydrogenation suggested by the increase in fraction of gases which are saturated hydrocarbons and the accompanying decrease in unsaturated hydrocarbons is consistent with the results of the oil analyses.

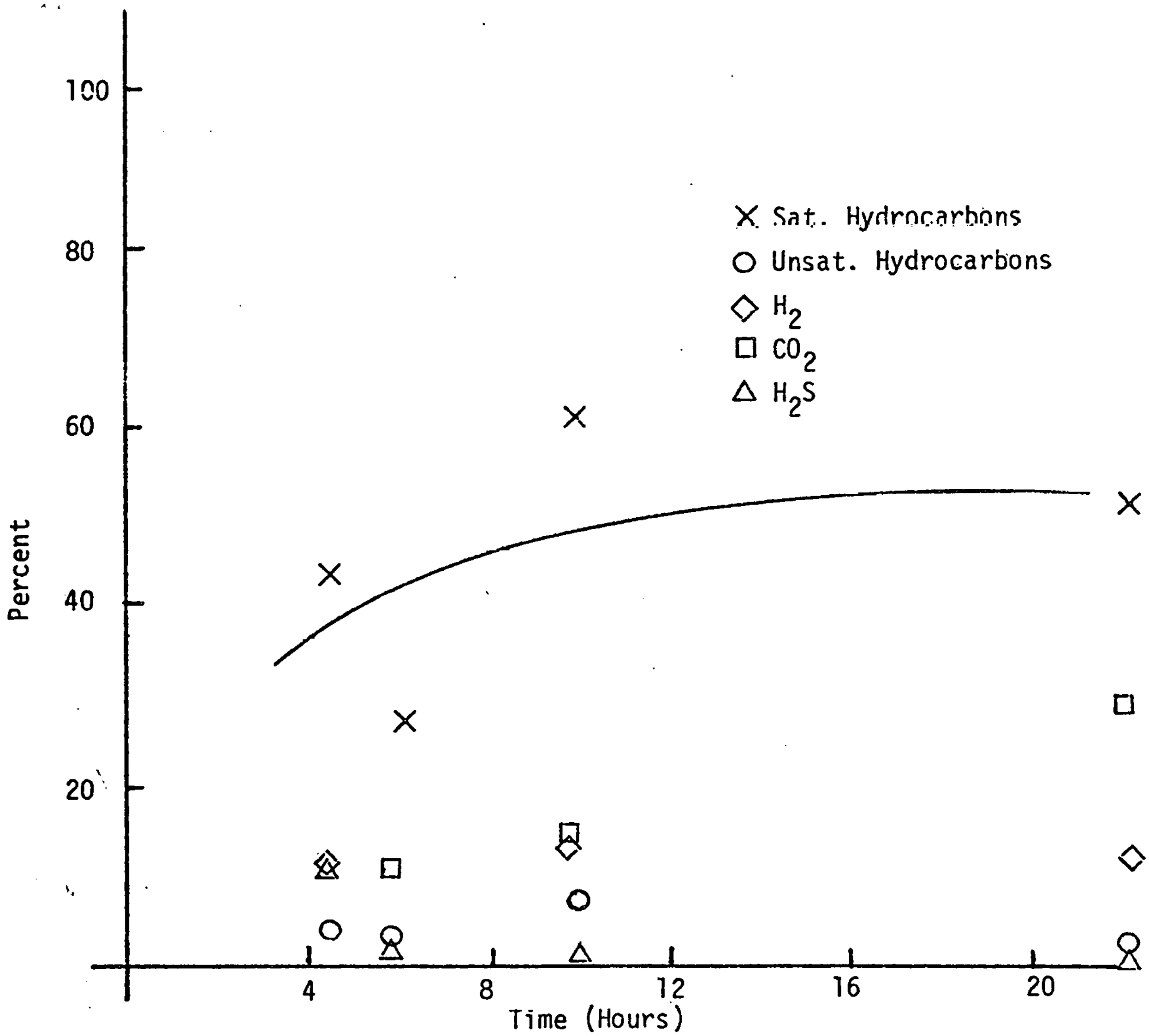

Figure 4

Gas Composition Over Oil During Steam Cracking at 550°F (288°C)

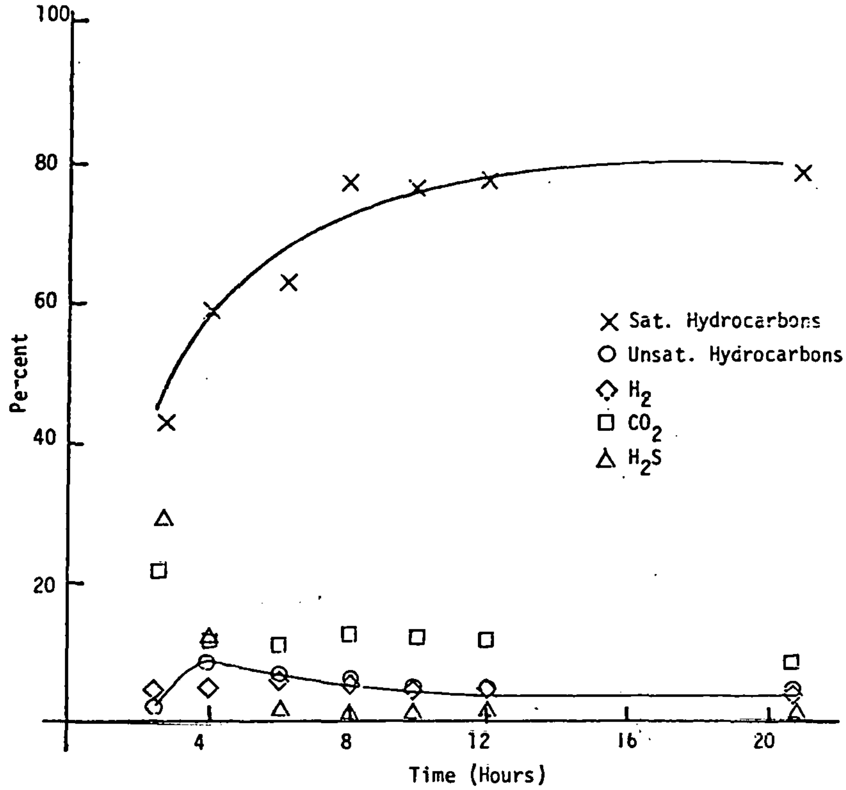

Figure 5

Gas Composition Over Oil During Steam Cracking at 700°F (371°C)

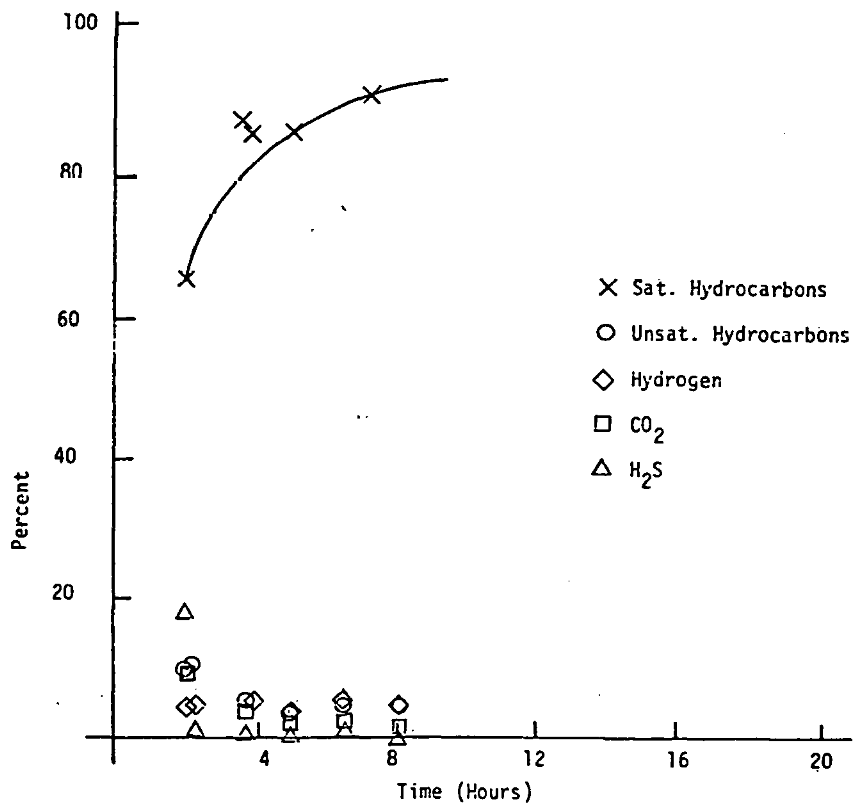

Figure 6

Gas Composition Over Oil During Steam Cracking at 850°F (454°C)

UTEC ME 80-049

QUARTERLY REPORT ON LABORATORY MODELING OF SUPER-HEATED STEAM RETORTING OF *In-situ* OIL SHALE

for the Period

1 December 1979 - 29 February 1980

Submitted to
Equity Oil Company
Salt Lake City, Utah

by

Harold R. Jacobs, Professor
Department of Mechanical and Industrial Engineering
University of Utah

March 1980

Introduction

During the period 1 December 1979 through 29 February 1980 the primary work effort has been directed toward the analyses of previously performed retort and autoclave experiments. However, one major retort experiment was performed in December. In addition, some additional work was performed utilizing the autoclave. Chemical analyses of the oil products progressed with the primary effort taking place in the last half of the quarter.

Retort Experiments

Retort 12 was performed early during this retorting period being completed in mid December. The experiment used BX-13 shale from essentially the same zone as Retort 11. The operating condition were:

Pressure	270 psig (1.862 MPa)	
Steam Flow Rate	51.6 lb/hr (23.4 kg/hr)	
Duration	21 hours	
Shale Size	Variable Core specimens and rubble	
Void Fraction	Shale Section 1	45.4%
	Shale Section 2	47.4%
	Section 3	100% (Empty)
	Section 4	100% (Empty)
Weight Loss	Section 1	16.3%
	Section 2	15.3%
Maximum Temperature Range	Section 1	946°F - 817°F
	Section 2	795°F - 714°F
	Section 3	543°F - 537°F
	Section 4	537°F - 536°F

The oil produced which was collected in Retort 12 totalled 4.51 lbs (2.05 kg) this amounted to 47.7% of the integrated Fisher Assay. The pour point of the oil was determined to be 41°F (5.0°C) with an API gravity of 26.6. During the experiment 8.4 cubic feet of gas was produced. The chemical composition of the oil was determined to be 83.4% C, 12.7% H, 1.4% N and 2.5% O and S. The C/H ratio for the oil was 6.57.

The characteristics of the oils produced for all twelve retort experiments and the operating characteristics are shown in Tables 1 and 2. Several conclusions can be drawn from evaluation of the data. In order to produce high percentages of Fisher Assay the temperatures within the shale must be of the order of 750°F or higher. Higher pressure and higher flow rates only slightly improve the performance.

The characteristics of the oil produced appear to be improved by increased surface area downstream of the production zone where the less volatile components can condense and then be revolatized. This appears to represent a thermal cracking (see Autoclave Experiments) and perhaps a de-carboxylizing as apparent by the decrease of the estimated oxygen and sulfur combination. The improvement in the oil is evident by a decrease in C/H ratio and a lower pour point.

Further chemical tests are needed to evaluate these ideas. In particular more detailed analyses will be conducted on oil produced in Retorts 4 and 11 during the remainder of the contract. TGA analyses are planned for these oils as well as characterization in terms of polarity and acidity. Other tests are planned to evaluate the product remaining in the retorted shale. Preliminary tests indicate that a major portion of the oil not recovered in many of the runs was left behind in the shale which did not reach 750°F. It is believed that this will be validated when TGA tests are completed on samples of shale

Table 2: Steam Retort Oil Properties

RETORTS Equity Oil Experiments	OIL DATA (1) Amount Produced,% Fisher Assay (2) Pour Point Temperature (3) API Gravity	Gases Produced	CHEMICAL ANALYSIS ON OIL C	H	N	O S (Wt %)	C/H
1	No oil produced	0					
2	N.A.,85% 70°F,(21.1°C) N.A.	60.0 c.f.	83	12.2	1.4	3.4*1	6.80
3	N.A. 65°F,(18.3°C) N.A.	55.0 c.f.	81.7	11.6	2.0	4.7*1	7.04
4	9.67Lbs(4.39Kg),85% 69°F,(20.6°C) 21.80	109.5 c.f.	83.8	12.1	1.9	2.2*1	6.93
5	6.08Lbs(2.76Kg),98.9% 67°F,(19.4°C) 26.95	N.A.	82.4	12.0	2.2	3.4*1	6.87
6	8.70Lbs(3.97Kg),69.5% 68°F,(20.0°C) 23.80	90.2 c.f.	83.4	12.0	1.6	3.0*1	6.95
7	6.07Lbs(2.75Kg),58.4% 71°F,(21.7°C) 26.60	N.A.	82.3	11.9	1.4	4.4*1	6.92
8	3.59Lbs(1.63Kg),34.6%* 58°F,(14.4°C) 25.40	N.A.	81.7	12.0	1.4	4.9*1	6.81
9	7.25Lbs(3.29Kg),98.0% 51°F,(10.6°C) 25.90	101.8 c.f.	82.4	11.9	1.9	3.8*1	6.92
10	5.10Lbs(2.31Kg),56.5% 27°F,(-2.78°C) 28.57	64.6 c.f.	82.9	12.2	1.7	3.2*1	6.80
11	5.76Lbs(2.61Kg),53.8% 27°F,(-2.78°C) 26.95	93.5 c.f.	84.6	13.0	1.4	0.9*1	6.51
12	4.51Lbs(2.05Kg),47.7% 41°F,(5.00°C) 26.60	85.4 c.f.	83.4	12.7	1.4	2.5*1	6.57

N.A. = Not Available
* = Estimated Value
1 = Combined O and S

Table 1: Steam Retort Experimental Operating Parameters

RETORTS Equity Oil Experiments	DURATION(HR)	PRESSURE	AVERAGE FLOW RATE	CHARACTERISTICS (1) Origin (2) Fisher Assay (3) Size	VESSEL DATA (1) Material Used, Void Fraction (2) Original-Final Weights,% Change (3) Inlet-Outlet Max, Temperatures(°F)
1	3.33	250 PSIG 1.724 MPa	200 to 300 LBS/HR 91 to 136 Kg/HR	Rifle,CO. 29 GAL/TON 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Gravel,N.A. Gravel,N.A. Shale,N.A. 78.5-78.5,0% 81.0-81.0,0% 77.0-77.0,0% 49.5-49.0,1% 754°-N.A. N.A.-N.A. N.A.-N.A. 529.7°-471.5°
2	6.17	270 PSIG 1.862 MPa	200 to 300 LBS/HR 91 to 136 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Gravel,N.A. Shale,N.A. 78.5-78.5,0% 77.0-77.0-0% 49.5-39.2,20.8% 1019°-N.A. N.A.-N.A. 860°-809° (Same Shale as First Experiment)
3	28.00	270 PSIG 1.862 MPa	40.1 LBS/HR 18.2 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,N.A. Shale,N.A. 78.5-78.5,0% 52-40,23% 50-49,2% 965°-N.A. 809°-724° 705°-643°
4	26.50	570 PSIG 3.930 MPa	51.9 LBS/HR 23.5 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,N.A. Shale,N.A. 78-78,0% 54.0-42.5,21.7% 53-45,14.8% 950°-N.A. 813°-741° 720°-663°
5	11.50	300 PSIG 2.068 MPa	78.1 LBS/HR 35.4 Kg/HR	Equity BX-12 L.A. Various Sizes	Gravel,N.A. Shale,40.8% Instrumented Shale Piece 78.5-78.5,0% 57.0-49.9,12.6% 967°-N.A. 868°-796° 794°
6	21.25	250 PSIG 1.725 MPa	68.6 LBS/HR 31.1 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,51.0% Shale,45.3% Sand,37.0% 78.5-78.5,0% 57.1-45.3,20.7% 56.7-47.2,16.8% 76.0-74.5,2.0% 971°-N.A. 886°-833° 823°-771° 763°- 724°
7	117.25	320 PSIG 2.206 MPa	39.8 LBS/HR 18.0 Kg/HR	Rifle,CO. 29 GAL/TON* 99.6 LIT/TONNE -3/4" to 5/8"+ -1.9cm to 1.6cm+	Gravel,N.A. Shale,47.3% Shale,48.4% 78.5-78.5,0% 52.2-42.6,18.4% 51.3-46.5,9.3% 868°-N.A. 732°-654° 652°-591°
8	101.00	300 PSIG 2.068 MPa	31.5 LBS/HR 12.6 Kg/HR	Equity BX-12 L.A. Various Sizes	Shale,46.5% Shale,50.6% Glass Wool, N.A. 56.0-50.1,10.5% 54.5-51.4,5.7% N.A. 761°-636° 621°-565° 560°-539°
9	17.00	250 PSIG 1.724 MPa	67.8 LBS/HR 30.7 Kg/HR	Equity BX-12 L.A. Various Sizes	Shale,44.0% Shale,45.9% Glass Wool,90.8% 50.6-42.0,17.0% 51.5-45.5,11.6% N.A. 1006°-900° 881°-832° 820-785°
10	18.00	570 PSIG 3.930 MPa	50.5 LBS/HR 22.9 Kg/HR	Equity BX-12 L.A. Various Sizes	Shale, N.A. Shale,N.A. Glass Wool,N.A. Glass Wool, N.A. 54.5-44.2,18.9% 58.6-45.6,6.8% N.A. N.A. 900°-784° 761°-665° 634°-594° 478°-395°
11	24.00	270 PSIG 1.862 MPa	50.1 LBS/HR 22.7 Kg/HR	Equity BX-13 L.A. Various Sizes	Shale,45.4% Shale,47.4% Glass Wool, N.A. Glass Wool, N.A. 49.9-40.2,19.5% 55.2-48.1,12.8% N.A. N.A. 960°-N.A. 761°-666° 635°-410° N.A.-N.A.
12	21.00	270 PSIG 1.862 MPa	51.6 LBS/HR 23.4 Kg/HR	Equity BX-13 L.A. Various Sizes	Shale,N.A. Shale,N.A. Empty Empty 56.3- 47.2, 16.3% 60.2-51.3,15.1% 946°-817° 795°-714° 543°-537° 537°-536°

N.A. = Not Available
L.A. = List Available
* = Estimated Value

from the retort experiments and raw shales from the same zone. These tests are currently being completed.

Autoclave Oil Cracking Experiments

Molecular Weight Measurements

The work on the autoclave measurements of steam cracking of oil has continued in the area of attempting to obtain accurate analytical measurements of the products of the experiments. The attempts to measure average molecular weights have proved frustrating. Duplicate runs have not given identical readings and results from samples sent to outside laboratories have not been internally consistent nor consistent with measurements made here.

Samples were sent to Huffman Laboratories, Inc. of Denver where average molecular weights were measured by vapor phase osmometry in pyridine. Reported molecular weights were 75% higher than measurements in camphor. Attempts to measure the molecular weight by using GC-MS techniques were also frustrated because of the inability of the laboratory which made the measurements to reduce the data for a mixture containing such a large number of species.

C, H, and N Analyses

The elemental analyses to determine the weight fractions of carbon, hydrogen, and nitrogen have been much more successful and hold the promise of being more useful in evaluating the kinetics of the cracking reactions. Measurements of the content of carbon, hydrogen, and nitrogen have been made on the Perkin-Elmer 240B elemental Analyzer on samples taken at various times during the cracking runs. The data is still being obtained, but preliminary results are shown in Table 3.

TABLE 3

Carbon, Hydrogen and Nitrogen Analyses

	C	H	N	(O&S)	C/H
Oil from Retort 6 (Starting Material)	83.4	12.0	1.6	3.0	6.95
After Cracking at 700°F in Steam					
8 Hours	84.9	12.6	1.2	1.2	6.72
10 Hours	84.3	12.6	1.1	1.7	6.66

Additional measurements are being made to ascertain the composition of the oil at times less than eight hours. However, these preliminary results do show that hydrogenation occurs during the cracking and that the nitrogen and sulfur content of the oil is decreased significantly during the cracking reactions.

A simple kinetic model based on the rate of formation of the hydrocarbon gases has been used to predict qualitatively the rate of gas formation and the observed pressure recovery that occurs after samples were taken from the reactor for anlaysis. The model is consistent with the observed hydrogenation of the oil by steam and the reduction in the C/H ratio.

APPENDIX "E"

NON-TECHNICAL DESCRIPTION AND FLOW CHARTS OF THE COMPUTERIZED DATA ACQUISITION AND ANALYSIS SYSTEM

FOR

EQUITY OIL COMPANY

BX IN SITU OIL SHALE PROJECT

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PHASE I - FIELD DATA COLLECTION (FIGURE 1)

SITE DESCRIPTION:

The BX IN SITU OIL SHALE PROJECT SITE is located in the center of the Piceance Creek Basin in Northwestern Colorado.

EQUIPMENT DESCRIPTION:

a. Consolidated Controls Micro-Processor Based Data-Logger

b. Sykes Comm-Stor - 7" Floppy Diskette Data Storage Unit, Capacity: 240,000 Characters

c. Beehive CRT - Console, Data Display, Controller

DATA COLLECTION:

Data is collected from 199 separate channels (see Attachment 1 for description). Data is generated via the following data-averaging system:

Each data channel has an associated accumulator with the capability of summing a maximum of 256 readings. A counter is incremented by one each time data is added to the accumulator. The time interval between each successive addition to the accumulator is determined by the number of data channels being scanned. For 199 channels the time is approximately one minute. At the end of each clock period (four hours) the arithmetic average is calculated by dividing the accumulator by the incremental counter, and the average is logged to the diskette device. The accumulator and the counter are both reset to zero. The five environmental channels have a special clock period of one hour.

DATA MONITORING:

Each channel scanned by the data logger can be monitored via two limits, both set high, both set low, or one high and the other low. Channels are scaled and settings made in engineering units. If either of these settings is exceeded, the channel number, time and reading are logged to the diskette.

PHASE I - DATA COLLECTION

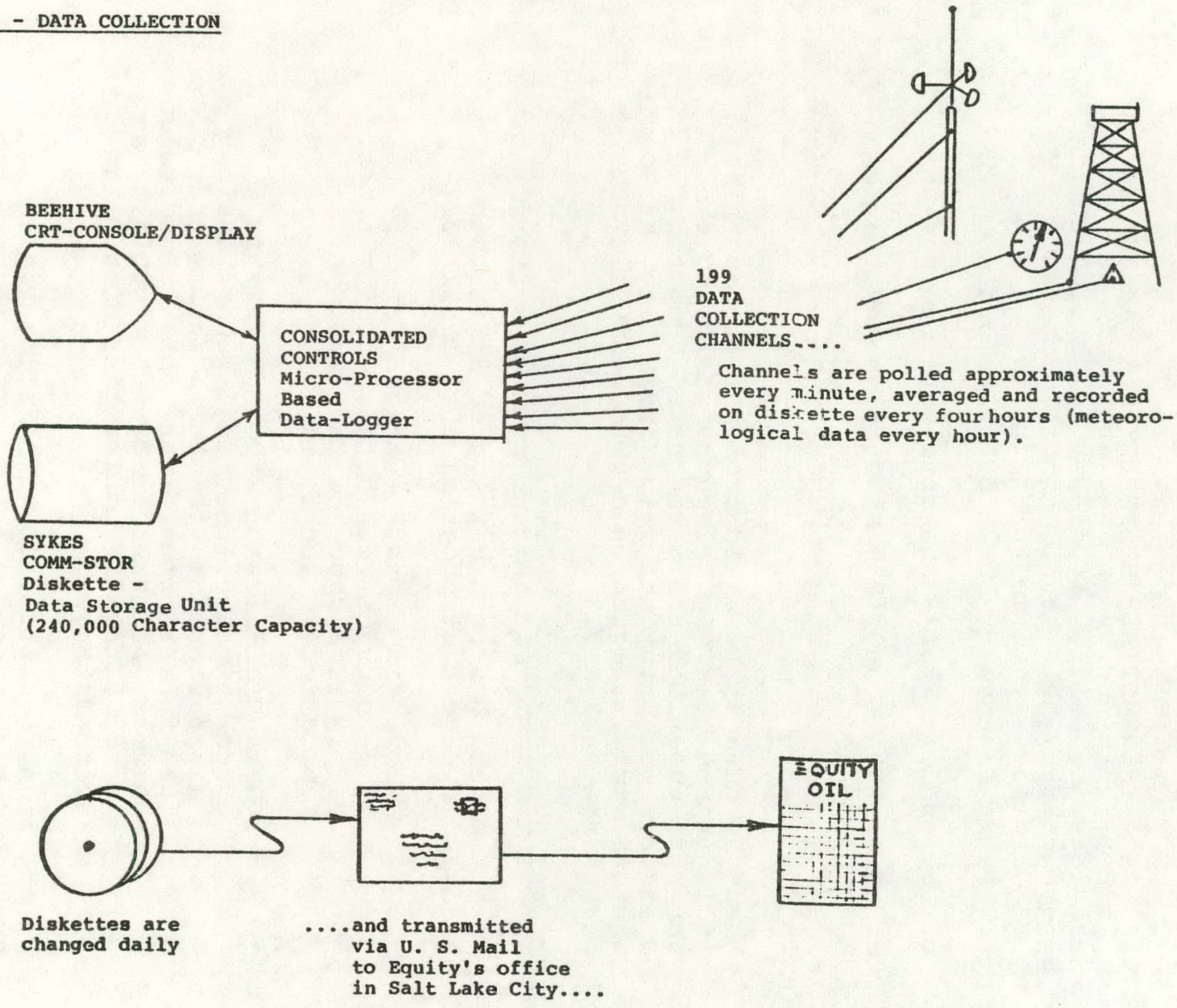


FIGURE 1

PHASE II - DATA TRANSMITTAL AND PRELIMINARY ANALYSIS (FIG. 2)

EQUIPMENT DESCRIPTION:

a. Texas Instruments OMNI 820 KSR Terminal

b. Sykes Comm-Stor - Diskette Data Storage Unit

c. Bell 212A - 300/1200 BAUD Telecommunications Modem

DATA TRANSMITTAL:

When the data is received from the project site, it is transmitted via telephone utilizing the terminal described above to United Computing Systems, Inc. Data Center in Kansas City, Missouri, where it is catalogued on a permanent file storage device for analysis.

PRELIMINARY ANALYSIS:

Once the data has been catalogued it is then analyzed by a set of programs that check for:

a. Sequencing Errors - A lapse of more than 1.5 hours between data recording times. (This is a check of the equipment operation in the field.)

b. Data Transmission Errors - This is a check of each individual record against a predetermined format to insure that the data is free of any data transmission errors, or other errors that could arise from voltage irregularities or similar circumstances.

In addition, a preliminary statistics report is produced which contains the recording count, the minimum, maximum, arithmetic average and standard deviation for each channel as well as limit checks on the various flow channels (i.e. check fuel flow channels to verify they are greater than a predetermined lower limit).

An example preliminary statistics report is included as Attachment 2.

Once the data has been verified, it is then ready to be merged into the data base for use in the operations report.

PHASE II - DATA TRANSMITTAL AND PRELIMINARY ANALYSIS

Salt Lake City On-Site Telecommunications Capability

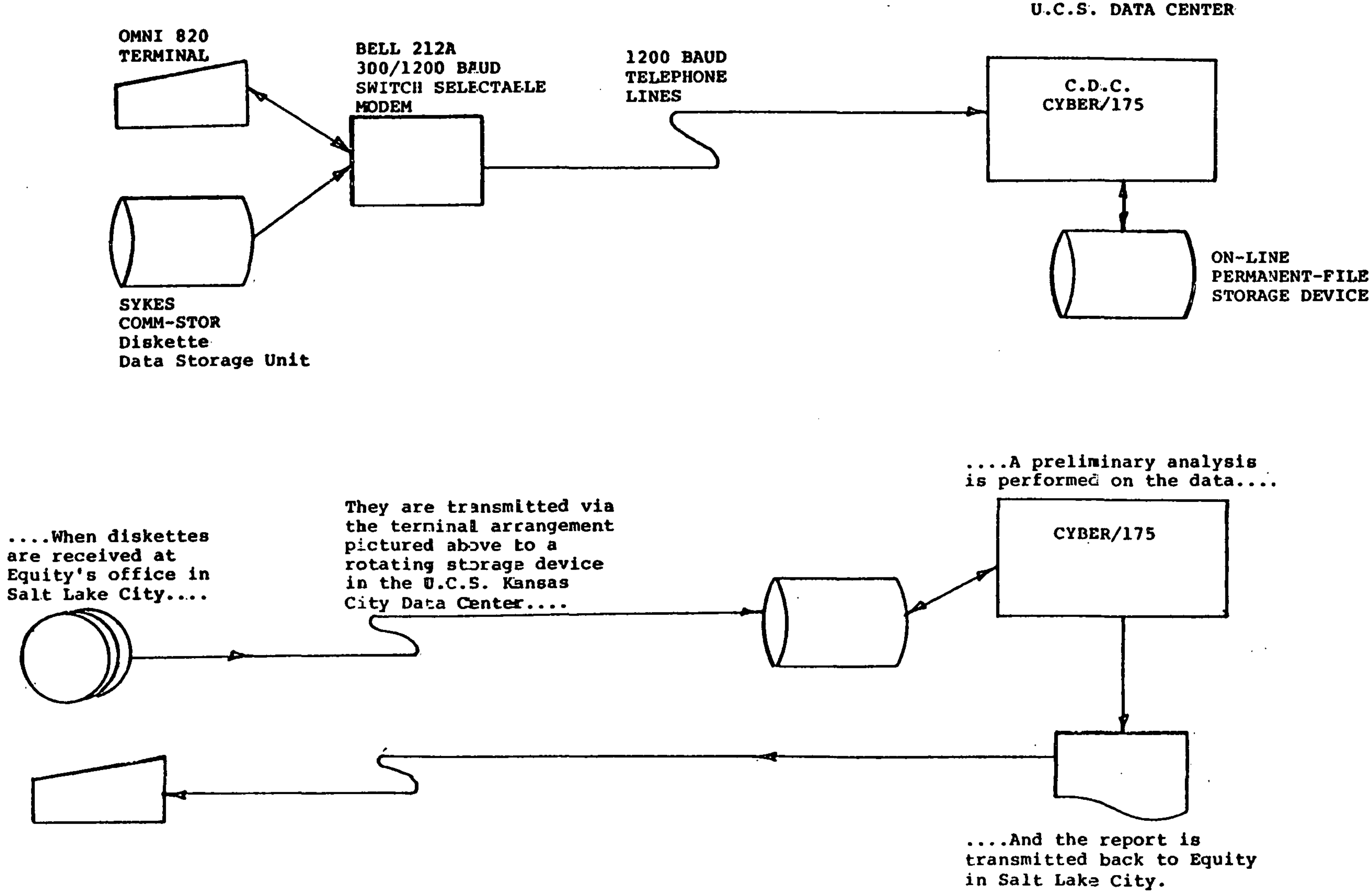


FIGURE 2

PHASE III - DATA CONSOLIDATION AND OPERATIONS REPORTING (FIGURE 3A)

DATA CONSOLIDATION:

Once the data has been verified, it is ready to be merged into the data base for use in the operations report. Subsequently two other actions are initiated.

a. The meteorological data is extracted and placed in a separate data file for transmission, via magnetic tape, to V.T.N. who is performing the environmental impact study.

b. The original data is archived on magnetic tape for historic purposes and further analysis.

OPERATIONS REPORTING:

The operations report is structured to give the project manager a review of the operation of the project throughout any time span that is deemed necessary. For system efficiency, the same report format is used for the monthly, quarterly, and yearly reports. The report shows the operation of the project throughout the time span, cumulative, and project-to-date figures for injection, production, fuel flow, steam generation, and related processes.

An example operations report is included as Attachment 3.

PHASE III - DATA CONSOLIDATION AND OPERATIONS REPORTING

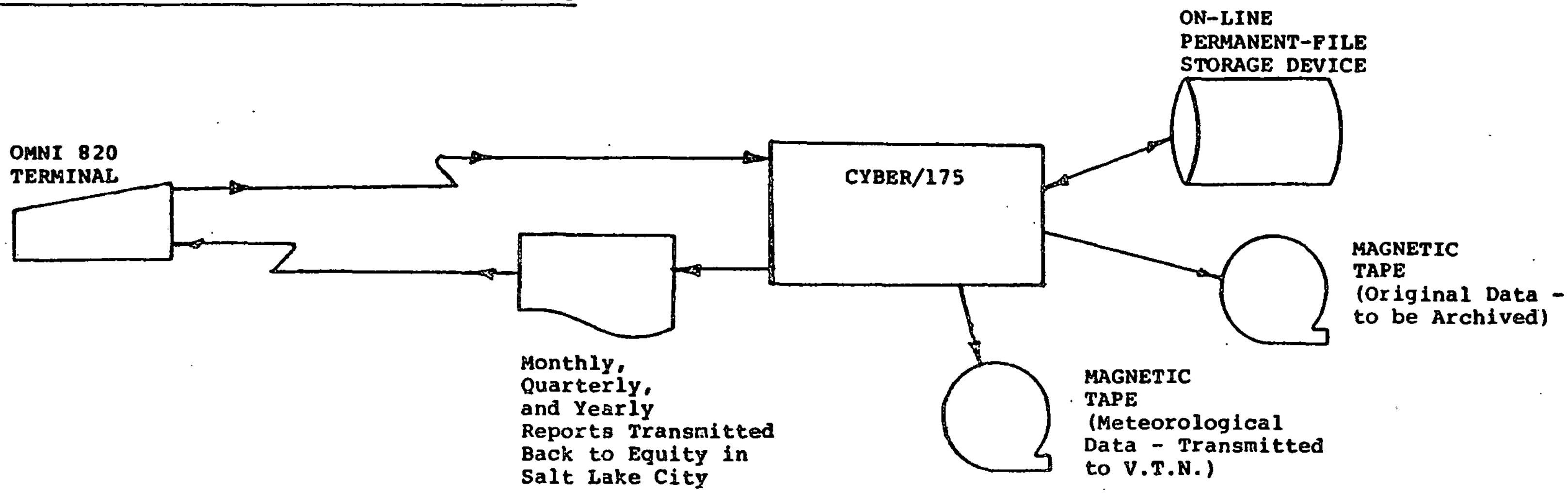
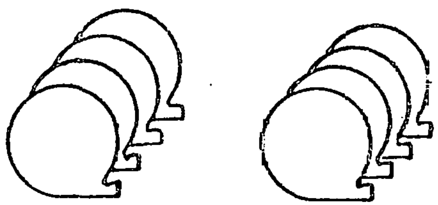


FIGURE 3A

PHASE IV - DATA TAPE ARCHIVAL



Data Tapes are Archived at
United Computing Service
and Retrieved as Necessary
for Monthly, Quarterly,
and Yearly Reports.

FIGURE 3B

PHASE IV - DATA ARCHIVING (FIGURE 3B)

PURPOSE:

All original data is archived on magnetic tape at the time when it is merged into the data base. In addition all data in the data base is archived at the end of each month. This archiving serves three purposes:

a. To keep processing and storage costs to a minimum.

b. As a historic record of the operation of the project should any questions arise at a later date.

c. For future analysis such as statistical evaluation, plotting of temperature profiles in the formation, plotting of production data, or other time-dependent analyses.

ATTACHMENT 1

CHANNEL NUMBER	DESCRIPTION	ENGR. UNITS
5	Gas From Test Separator	MFD
6	Free Water From Test Separator	BPD
7	Oil Emulsion From Test Separator	BPD
8	% Water in Emulsion-Test Separator	%
9	Gas From Freewater K.O.	MFD
10	Free Water From Freewater K.O.	BPD
11	Oil Emulsion From Freewater K.O.	BPD
12	% Water in Emulsion-Freewater K.O.	%
16	Injection Well #1 Flow Rate	Lb/h
17	Injection Well #2 Flow Rate	Lb/h
18	Injection Well #3 Flow Rate	Lb/h
19	Injection Well #4 Flow Rate	Lb/h
20	Injection Well #5 Flow Rate	Lb/h
21	Injection Well #6 Flow Rate	Lb/h
22	Injection Well #7 Flow Rate	Lb/h
23	Injection Well #8 Flow Rate	Lb/h
28	Total Steam to Super Heater	Lb/h
29	Downhole Pressure, Test Well No. 1	PSI
30	Super Heater Disch. Temperature	°F
31	Super Heater Disch. Pressure	PSI
32	Injection Well #1 Pressure	PSI
33	Injection Well #2 Pressure	PSI
34	Injection Well #3 Pressure	PSI
35	Injection Well #4 Pressure	PSI
36	Injection Well #5 Pressure	PSI
37	Injection Well #6 Pressure	PSI
38	Injection Well #7 Pressure	PSI
39	Injection Well #8 Pressure	PSI
40	Downhole Pressure, Test Well No. 2	PSI
41	Downhole Pressure, Test Well No. 3	PSI
44	Exist. Stm. Gen.-Feedwater Rate	GPM
45	New Stm. Gen.-Feedwater Rate	GPM
46	Hardness Monitor-Stm. Plant No. 1	%
47	Hardness Monitor-Stm. Plant No. 2	%
48	Total Gas Lift Flow Rate	MFD
49	Exist. Steam Gen. - Fuel Flow	MFD
50	New Steam Gen. - Fuel Flow	MFD
51	Super Heater - Fuel Flow	MFD
52	Total Facility - Fuel Flow	MFD
57	Turbidity From Water Filter	%
58	Stack SO_2 Content	%
59	Water From Vertical Treater	BPD
60	Water From Steam Separators	BPD
61	Water From Backwash Filters	BPD
64	Wind Speed	MPh
65	Wind Direction	D

CHANNEL NUMBER	DESCRIPTION	ENGR. UNITS
66	Wind Deviation	%
67	Ambient Temperature	°C
68	Structure Differential Temperature	%
72	Production Well #0 Liquid Flow	%
73	Production Well #1 Liquid Flow	%
74	Production Well #2 Liquid Flow	%
75	Production Well #3 Liquid Flow	%
76	Production Well #4 Liquid Flow	%
257	Exist. Steam Gen. Stack Temperature	°F
258	New Steam Gen. Stack Temperature	°F
259	Super Heater Stack Temperature	°F
260	Test Well No. 1 - 450'	°F
261	- 500'	
262	- 600'	
263	- 700'	
264	- 760'	
265	- 780'	
266	- 800'	
267	- 820'	
268	- 840'	
269	- 860'	
270	- 880'	
271	- 900'	
273	- 920'	
274	- 940'	
275	- 960'	
276	- 980'	
277	- 1000'	
278	- 1020'	
279	- 1040'	
280	- 1060'	
281	- 1080'	
282	- 1100'	
283	- 1120'	
284	- 1140'	
285	- 1160'	
286	- 1180'	
287	- 1200'	
289	- 1220'	
290	- 1240'	
291	- 1260'	
292	- 1280'	
293	- 1300'	
294	- 1320'	
295	- 1340'	
296	- 1360'	
297	Test Well No. 2 - 450'	°F
298	- 500'	
299	- 600'	
300	- 700'	

CHANNEL NUMBER	DESCRIPTION	ENGR. UNITS
301	Test Well No. 2 - 760'	°F
302	- 780'	
303	- 800'	
305	- 820'	
306	- 840'	
307	- 860'	
308	- 880'	
309	- 900'	
310	- 920'	
311	- 940'	
312	- 960'	
313	- 980'	
314	- 1000'	
315	- 1020'	
316	- 1040'	
317	- 1060'	
318	- 1080'	
319	- 1100'	
321	- 1120'	
322	- 1140'	
323	- 1160'	
324	- 1180'	
325	- 1200'	
326	- 1220'	
327	- 1240'	
328	- 1260'	
329	- 1280'	
330	- 1300'	
331	- 1320'	
332	- 1340'	
333	- 1360'	
334	Test Well No. 3 - 450'	°F
335	- 500'	
337	- 600'	
338	- 700'	
339	- 760'	
340	- 780'	
341	- 800'	
342	- 820'	
343	- 840'	
344	- 860'	
345	- 880'	
346	- 900'	
347	- 920'	
348	- 940'	
349	- 960'	
350	- 980'	
351	- 1000'	
353	- 1020'	
354	- 1040'	
355	- 1060'	

CHANNEL NUMBER	DESCRIPTION	ENGR. UNITS
356	Test Well No. 3 - 1080'	°F
357	- 1100'	
358	- 1120'	
359	- 1140'	
360	- 1160	
361	- 1180'	
362	- 1200'	
363	- 1220'	
364	- 1240'	
365	- 1260'	
366	- 1280'	
367	- 1300'	
369	- 1320'	
370	- 1340'	
371	Injection Well #1-Temp. at Wellhead	
372	Injection Well #2-Temp. at Wellhead	
373	Injection Well #3-Temp. at Wellhead	
374	Injection Well #4-Temp. at Wellhead	
375	Injection Well #5-Temp. at Wellhead	
376	Injection Well #6-Temp. at Wellhead	
377	Injection Well #7-Temp. at Wellhead	
378	Injection Well #8-Temp. at Wellhead	
379	Production Well #0-Temp. at Wellhead	
380	Production Well #1-Temp. at Wellhead	
381	Production Well #2-Temp. at Wellhead	
382	Production Well #3-Temp. at Wellhead	
383	Production Well #4-Temp. at Wellhead	°F

DATA COLLECTION FOR MARCH 6, 1980 AT 13:43:52
DATA COLLECTION FOR MARCH 6, 1980 AT 13:45:24
DATA COLLECTION FOR MARCH 6, 1980 AT 16:00:00
DATA COLLECTION FOR MARCH 6, 1980 AT 20:00:00
DATA COLLECTION FOR MARCH 6, 1980 AT 23:57:56

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CHNL 560 MIN +00307.50 MAX +00323.80 CNT   3 AVG +00317.97 DEV     9.08 NEG-CNT   0
CHNL 561 MIN +00000.60 MAX +00000.60 CNT   3 AVG +00000.60 DEV     0.00 NEG-CNT   0    *** NO FUEL FLOW(<10) ***
CHNL 562 MIN +00344.40 MAX +00360.50 CNT   3 AVG +00349.80 DEV     9.27 NEG-CNT   0
CHNL 563 MIN +00002.50 MAX +00002.50 CNT   3 AVG +00002.50 DEV     0.00 NEG-CNT   0    *** NO FUEL FLOW(<10) ***
CHNL 564 MIN +00477.00 MAX +00488.00 CNT   3 AVG +00482.33 DEV     5.51 NEG-CNT   0
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CHNL 570 NEG-CNT   3
CHNL 571 NEG-CNT   3
CHNL 572 MIN +00020.10 MAX +00148.60 CNT   3 AVG +00100.43 DEV    70.03 NEG-CNT   0
CHNL 573 MIN +00000.30 MAX +00041.10 CNT   3 AVG +00016.07 DEV    21.92 NEG-CNT   0
CHNL 574---NO DATA---
CHNL 575---NO DATA---
CHNL 576---NO DATA---
CHNL 577---NO DATA---
CHNL 578---NO DATA---
```

PRELIMINARY STATISTICS FOR BX IN SITU OIL SHALE PROJECT

CHNL 579---NO DATA---
CHNL 580---NO DATA---
CHNL 581---NO DATA---
CHNL 582---NO DATA---
CHNL 583---NO DATA---

CHNL	584	MIN	+00026.20	MAX	+00027.30	CNT	3	AVG	+00026.77	DEV	0.55	NEG-CNT	0
CHNL	585	MIN	+00038.30	MAX	+00045.90	CNT	3	AVG	+00042.27	DEV	3.81	NEG-CNT	0
CHNL	586	MIN	+00000.80	MAX	+00000.80	CNT	2	AVG	+00000.80	DEV	0.00	NEG-CNT	1
CHNL	587	MIN	+00032.00	MAX	+00032.30	CNT	3	AVG	+00032.20	DEV	0.17	NEG-CNT	0
CHNL	588	MIN	+00019.20	MAX	+00020.30	CNT	3	AVG	+00019.90	DEV	0.61	NEG-CNT	0

----- NO DATA COLLECTED FOR CHANNELS 589 - 768 -----

CHNL	769	MIN	+00029.70	MAX	+00054.10	CNT	3	AVG	+00039.83	DEV	12.71	NEG-CNT	0
CHNL	770	MIN	+00515.30	MAX	+00521.70	CNT	3	AVG	+00518.50	DEV	3.20	NEG-CNT	0
CHNL	771	MIN	+00031.50	MAX	+00034.90	CNT	3	AVG	+00033.53	DEV	1.80	NEG-CNT	0
CHNL	772	MIN	+00058.20	MAX	+00058.20	CNT	3	AVG	+00058.20	DEV	0.00	NEG-CNT	0
CHNL	773	MIN	+00058.60	MAX	+00058.60	CNT	3	AVG	+00058.60	DEV	0.00	NEG-CNT	0
CHNL	774	MIN	+00061.90	MAX	+00061.90	CNT	3	AVG	+00061.90	DEV	0.00	NEG-CNT	0
CHNL	775	MIN	+00067.50	MAX	+00067.60	CNT	3	AVG	+00067.53	DEV	0.06	NEG-CNT	0
CHNL	776	MIN	+00066.90	MAX	+00066.90	CNT	3	AVG	+00066.90	DEV	0.00	NEG-CNT	0
CHNL	777	MIN	+00066.90	MAX	+00066.90	CNT	3	AVG	+00066.90	DEV	0.00	NEG-CNT	0
CHNL	778	MIN	+00077.80	MAX	+00077.90	CNT	3	AVG	+00077.87	DEV	0.06	NEG-CNT	0
CHNL	779	MIN	+00137.40	MAX	+00138.20	CNT	3	AVG	+00137.80	DEV	0.40	NEG-CNT	0
CHNL	780	MIN	+00198.80	MAX	+00201.40	CNT	3	AVG	+00200.20	DEV	1.31	NEG-CNT	0
CHNL	781	MIN	+00378.50	MAX	+00384.80	CNT	3	AVG	+00380.70	DEV	3.55	NEG-CNT	0
CHNL	782	MIN	+00491.10	MAX	+00492.60	CNT	3	AVG	+00492.03	DEV	0.81	NEG-CNT	0
CHNL	783	MIN	+00139.10	MAX	+00142.10	CNT	3	AVG	+00140.57	DEV	1.50	NEG-CNT	0
CHNL	784	MIN	+00029.80	MAX	+00030.10	CNT	3	AVG	+00029.97	DEV	0.15	NEG-CNT	0
CHNL	785	MIN	+00077.60	MAX	+00079.80	CNT	3	AVG	+00078.67	DEV	1.10	NEG-CNT	0
CHNL	786	MIN	+00094.50	MAX	+00097.00	CNT	3	AVG	+00095.50	DEV	1.32	NEG-CNT	0
CHNL	787	MIN	+00101.90	MAX	+00104.30	CNT	3	AVG	+00102.73	DEV	1.36	NEG-CNT	0
CHNL	788	MIN	+00097.10	MAX	+00100.20	CNT	3	AVG	+00098.93	DEV	1.63	NEG-CNT	0
CHNL	789	MIN	+00099.90	MAX	+00103.50	CNT	3	AVG	+00102.00	DEV	1.87	NEG-CNT	0
CHNL	790	MIN	+00147.90	MAX	+00158.30	CNT	3	AVG	+00154.03	DEV	5.45	NEG-CNT	0
CHNL	791	MIN	+00163.40	MAX	+00173.70	CNT	3	AVG	+00166.90	DEV	5.89	NEG-CNT	0
CHNL	792	MIN	+00092.20	MAX	+00094.50	CNT	3	AVG	+00093.43	DEV	1.16	NEG-CNT	0
CHNL	793	MIN	+00077.60	MAX	+00082.60	CNT	3	AVG	+00080.23	DEV	2.51	NEG-CNT	0
CHNL	794	MIN	+00116.40	MAX	+00134.50	CNT	3	AVG	+00123.93	DEV	9.42	NEG-CNT	0
CHNL	795	MIN	+00079.80	MAX	+00091.00	CNT	3	AVG	+00083.97	DEV	6.13	NEG-CNT	0
CHNL	796	MIN	+00145.90	MAX	+00157.10	CNT	3	AVG	+00153.23	DEV	6.35	NEG-CNT	0
CHNL	797	MIN	+00088.20	MAX	+00103.80	CNT	3	AVG	+00096.27	DEV	7.81	NEG-CNT	0
CHNL	798	MIN	+00078.90	MAX	+00092.70	CNT	3	AVG	+00086.87	DEV	7.14	NEG-CNT	0
CHNL	799	MIN	+00128.70	MAX	+00146.60	CNT	3	AVG	+00138.17	DEV	8.99	NEG-CNT	0
CHNL	800	MIN	+00026.90	MAX	+00027.20	CNT	3	AVG	+00027.10	DEV	0.17	NEG-CNT	0
CHNL	801	MIN	+00060.90	MAX	+00065.30	CNT	3	AVG	+00062.93	DEV	2.22	NEG-CNT	0
CHNL	802	MIN	+00114.00	MAX	+00123.70	CNT	3	AVG	+00118.60	DEV	4.87	NEG-CNT	0
CHNL	803	MIN	+00089.50	MAX	+00093.70	CNT	3	AVG	+00092.10	DEV	2.27	NEG-CNT	0
CHNL	804	MIN	+00314.10	MAX	+00316.60	CNT	3	AVG	+00315.03	DEV	1.37	NEG-CNT	0
CHNL	805	MIN	+00137.80	MAX	+00142.50	CNT	3	AVG	+00140.30	DEV	2.36	NEG-CNT	0
CHNL	806	MIN	+00113.50	MAX	+00126.90	CNT	3	AVG	+00120.47	DEV	6.72	NEG-CNT	0
CHNL	807	MIN	+00114.80	MAX	+00125.10	CNT	3	AVG	+00119.67	DEV	5.17	NEG-CNT	0
CHNL	808	MIN	+00112.50	MAX	+00126.20	CNT	3	AVG	+00118.50	DEV	7.01	NEG-CNT	0
CHNL	809	MIN	+00203.30	MAX	+00213.40	CNT	3	AVG	+00206.80	DEV	5.72	NEG-CNT	0
CHNL	810	MIN	+00152.70	MAX	+00155.30	CNT	3	AVG	+00153.73	DEV	1.38	NEG-CNT	0
CHNL	811	MIN	+00132.00	MAX	+00140.90	CNT	3	AVG	+00135.10	DEV	5.03	NEG-CNT	0
CHNL	812	MIN	+00143.30	MAX	+00152.00	CNT	3	AVG	+00146.33	DEV	4.91	NEG-CNT	0
CHNL	813	MIN	+00217.80	MAX	+00236.40	CNT	3	AVG	+00225.87	DEV	9.54	NEG-CNT	0
CHNL	814	MIN	+00085.80	MAX	+00087.70	CNT	3	AVG	+00087.07	DEV	1.10	NEG-CNT	0
CHNL	815	MIN	+00248.40	MAX	+00272.00	CNT	3	AVG	+00258.67	DEV	12.10	NEG-CNT	0
CHNL	816	MIN	+00027.70	MAX	+00028.00	CNT	3	AVG	+00027.90	DEV	0.17	NEG-CNT	0
CHNL	817	MIN	+00107.80	MAX	+00107.80	CNT	3	AVG	+00107.80	DEV	0.00	NEG-CNT	0
CHNL	818	MIN	+00099.90	MAX	+00100.00	CNT	3	AVG	+00099.97	DEV	0.06	NEG-CNT	0

CHNL	819	MIN	+00100.10	MAX	+00100.20	CNT	3	AVG	+00100.13	DEV	0.06	NEG-CNT	0
CHNL	820	MIN	+00105.10	MAX	+00105.20	CNT	3	AVG	+00105.17	DEV	0.06	NEG-CNT	0
CHNL	821	MIN	+00099.30	MAX	+00099.30	CNT	3	AVG	+00099.30	DEV	0.00	NEG-CNT	0
CHNL	822	MIN	+00105.50	MAX	+00105.50	CNT	3	AVG	+00105.50	DEV	0.00	NEG-CNT	0
CHNL	823	MIN	+00109.70	MAX	+00109.80	CNT	3	AVG	+00109.77	DEV	0.06	NEG-CNT	0
CHNL	824	MIN	+00123.50	MAX	+00123.80	CNT	3	AVG	+00123.63	DEV	0.15	NEG-CNT	0
CHNL	825	MIN	+00171.10	MAX	+00171.30	CNT	3	AVG	+00171.20	DEV	0.10	NEG-CNT	0
CHNL	826	MIN	+00225.30	MAX	+00225.60	CNT	3	AVG	+00225.50	DEV	0.17	NEG-CNT	0
CHNL	827	MIN	+00200.70	MAX	+00201.20	CNT	3	AVG	+00201.03	DEV	0.29	NEG-CNT	0
CHNL	828	MIN	+00123.00	MAX	+00123.10	CNT	3	AVG	+00123.07	DEV	0.06	NEG-CNT	0
CHNL	829	MIN	+00093.50	MAX	+00093.50	CNT	3	AVG	+00093.50	DEV	0.00	NEG-CNT	0
CHNL	830	MIN	+00056.60	MAX	+00056.60	CNT	3	AVG	+00056.60	DEV	0.00	NEG-CNT	0
CHNL	831	MIN	+00057.50	MAX	+00057.60	CNT	3	AVG	+00057.53	DEV	0.06	NEG-CNT	0
CHNL	832	MIN	+00026.80	MAX	+00027.10	CNT	3	AVG	+00027.00	DEV	0.17	NEG-CNT	0
CHNL	833	MIN	+00059.50	MAX	+00059.60	CNT	3	AVG	+00059.53	DEV	0.06	NEG-CNT	0
CHNL	834	MIN	+00062.30	MAX	+00062.40	CNT	3	AVG	+00062.37	DEV	0.06	NEG-CNT	0
CHNL	835	MIN	+00064.50	MAX	+00064.50	CNT	3	AVG	+00064.50	DEV	0.00	NEG-CNT	0
CHNL	836	MIN	+00067.50	MAX	+00067.50	CNT	3	AVG	+00067.50	DEV	0.00	NEG-CNT	0
CHNL	837	MIN	+00075.10	MAX	+00075.20	CNT	3	AVG	+00075.17	DEV	0.06	NEG-CNT	0
CHNL	838	MIN	+00122.10	MAX	+00122.30	CNT	3	AVG	+00122.20	DEV	0.10	NEG-CNT	0
CHNL	839	MIN	+00161.10	MAX	+00161.10	CNT	3	AVG	+00161.10	DEV	0.00	NEG-CNT	0
CHNL	840	MIN	+00301.50	MAX	+00302.90	CNT	3	AVG	+00302.27	DEV	0.71	NEG-CNT	0
CHNL	841	MIN	+00368.90	MAX	+00369.50	CNT	3	AVG	+00369.17	DEV	0.31	NEG-CNT	0
CHNL	842	MIN	+00095.80	MAX	+00097.80	CNT	3	AVG	+00096.77	DEV	1.00	NEG-CNT	0
CHNL	843	MIN	+00083.20	MAX	+00084.30	CNT	3	AVG	+00083.60	DEV	0.61	NEG-CNT	0
CHNL	844	MIN	+00070.20	MAX	+00073.50	CNT	3	AVG	+00072.03	DEV	1.68	NEG-CNT	0
CHNL	845	MIN	+00095.30	MAX	+00107.60	CNT	3	AVG	+00101.87	DEV	6.19	NEG-CNT	0
CHNL	846	MIN	+00089.50	MAX	+00096.20	CNT	3	AVG	+00092.60	DEV	3.38	NEG-CNT	0
CHNL	847	MIN	+00088.30	MAX	+00093.50	CNT	3	AVG	+00090.07	DEV	2.97	NEG-CNT	0
CHNL	848	MIN	+00026.50	MAX	+00026.80	CNT	3	AVG	+00026.70	DEV	0.17	NEG-CNT	0
CHNL	849	MIN	+00114.90	MAX	+00115.40	CNT	3	AVG	+00115.13	DEV	0.25	NEG-CNT	0
CHNL	850	MIN	+00168.40	MAX	+00168.60	CNT	3	AVG	+00168.53	DEV	0.12	NEG-CNT	0
CHNL	851	MIN	+00146.10	MAX	+00147.20	CNT	3	AVG	+00146.67	DEV	0.55	NEG-CNT	0
CHNL	852	MIN	+00128.80	MAX	+00129.10	CNT	3	AVG	+00128.97	DEV	0.15	NEG-CNT	0
CHNL	853	MIN	+00084.40	MAX	+00084.40	CNT	3	AVG	+00084.40	DEV	0.00	NEG-CNT	0
CHNL	854	MIN	+00086.50	MAX	+00086.60	CNT	3	AVG	+00086.53	DEV	0.06	NEG-CNT	0
CHNL	855	MIN	+00084.30	MAX	+00084.40	CNT	3	AVG	+00084.33	DEV	0.06	NEG-CNT	0
CHNL	856	MIN	+00083.80	MAX	+00084.00	CNT	3	AVG	+00083.90	DEV	0.10	NEG-CNT	0
CHNL	857	MIN	+00084.30	MAX	+00084.40	CNT	3	AVG	+00084.33	DEV	0.06	NEG-CNT	0
CHNL	858	MIN	+00086.40	MAX	+00086.50	CNT	3	AVG	+00086.47	DEV	0.06	NEG-CNT	0
CHNL	859	MIN	+00087.80	MAX	+00087.80	CNT	3	AVG	+00087.80	DEV	0.00	NEG-CNT	0
CHNL	860	MIN	+00095.10	MAX	+00095.20	CNT	3	AVG	+00095.13	DEV	0.06	NEG-CNT	0
CHNL	861	MIN	+00097.30	MAX	+00097.40	CNT	3	AVG	+00097.37	DEV	0.06	NEG-CNT	0
CHNL	862	MIN	+00102.30	MAX	+00102.30	CNT	3	AVG	+00102.30	DEV	0.00	NEG-CNT	0
CHNL	863	MIN	+00107.90	MAX	+00108.00	CNT	3	AVG	+00107.97	DEV	0.06	NEG-CNT	0
CHNL	864	MIN	+00027.10	MAX	+00027.50	CNT	3	AVG	+00027.37	DEV	0.23	NEG-CNT	0
CHNL	865	MIN	+00028.90	MAX	+00057.50	CNT	3	AVG	+00044.00	DEV	14.37	NEG-CNT	0
CHNL	866	MIN	+00100.10	MAX	+00129.90	CNT	3	AVG	+00117.17	DEV	15.37	NEG-CNT	0
CHNL	867	MIN	+00172.80	MAX	+00195.30	CNT	3	AVG	+00185.73	DEV	11.62	NEG-CNT	0
CHNL	868	MIN	+00125.30	MAX	+00136.80	CNT	3	AVG	+00131.53	DEV	5.81	NEG-CNT	0
CHNL	869	MIN	+00179.10	MAX	+00190.40	CNT	3	AVG	+00184.97	DEV	5.66	NEG-CNT	0
CHNL	870	MIN	+00205.00	MAX	+00208.40	CNT	3	AVG	+00206.17	DEV	1.93	NEG-CNT	0
CHNL	871	MIN	+00059.30	MAX	+00102.80	CNT	3	AVG	+00088.17	DEV	25.00	NEG-CNT	0
CHNL	872	MIN	+00190.20	MAX	+00204.10	CNT	3	AVG	+00197.80	DEV	7.04	NEG-CNT	0
CHNL	873	MIN	+00061.00	MAX	+00061.10	CNT	3	AVG	+00061.07	DEV	0.06	NEG-CNT	0
CHNL	874	MIN	+00065.60	MAX	+00065.60	CNT	3	AVG	+00065.60	DEV	0.00	NEG-CNT	0
CHNL	875	MIN	+00066.20	MAX	+00066.20	CNT	3	AVG	+00066.20	DEV	0.00	NEG-CNT	0
CHNL	876	MIN	+00068.00	MAX	+00068.00	CNT	3	AVG	+00068.00	DEV	0.00	NEG-CNT	0
CHNL	877	MIN	+00070.30	MAX	+00070.40	CNT	3	AVG	+00070.33	DEV	0.06	NEG-CNT	0
CHNL	878	MIN	+00072.90	MAX	+00073.00	CNT	3	AVG	+00072.93	DEV	0.06	NEG-CNT	0
CHNL	879	MIN	+00084.00	MAX	+00084.10	CNT	3	AVG	+00084.07	DEV	0.06	NEG-CNT	0
CHNL	880	MIN	+00025.90	MAX	+00026.40	CNT	3	AVG	+00026.20	DEV	0.26	NEG-CNT	0

PRELIMINARY STATISTICS FOR BX IN SITU OIL SHALE PROJECT

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CHNL 881 MIN +00189.30 MAX +00204.80 CNT   3 AVG +00197.17 DEV     7.75 NEG-CNT   0
CHNL 882 MIN +00241.40 MAX +00248.20 CNT   3 AVG +00245.67 DEV     3.72 NEG-CNT   0
CHNL 883 MIN +00450.00 MAX +00464.80 CNT   3 AVG +00458.83 DEV     7.81 NEG-CNT   0
CHNL 884 MIN +00499.50 MAX +00504.30 CNT   3 AVG +00501.47 DEV     2.51 NEG-CNT   0
CHNL 885 MIN +00484.90 MAX +00490.40 CNT   3 AVG +00487.87 DEV     2.78 NEG-CNT   0
CHNL 886 MIN +00486.40 MAX +00505.70 CNT   3 AVG +00494.97 DEV     9.83 NEG-CNT   0
CHNL 887 MIN +00405.10 MAX +00502.70 CNT   3 AVG +00461.67 DEV    50.62 NEG-CNT   0
CHNL 888 MIN +00386.50 MAX +00409.90 CNT   3 AVG +00398.63 DEV    11.72 NEG-CNT   0
CHNL 889 MIN +00569.30 MAX +00573.40 CNT   3 AVG +00570.73 DEV     2.31 NEG-CNT   0
CHNL 890 MIN +00568.10 MAX +00570.30 CNT   3 AVG +00569.00 DEV     1.15 NEG-CNT   0
CHNL 891 MIN +00062.90 MAX +00065.20 CNT   3 AVG +00064.07 DEV     1.15 NEG-CNT   0
CHNL 892 MIN +00045.20 MAX +00056.60 CNT   3 AVG +00050.20 DEV     5.83 NEG-CNT   0
CHNL 893 MIN +00035.00 MAX +00040.20 CNT   3 AVG +00038.13 DEV     2.76 NEG-CNT   0
CHNL 894 MIN +00099.20 MAX +00099.50 CNT   3 AVG +00099.33 DEV     0.15 NEG-CNT   0
CHNL 895 MIN +00025.50 MAX +00030.80 CNT   3 AVG +00028.87 DEV     2.93 NEG-CNT   0

 ***550 RECORDS INPUT
 ***167 RECORDS OUTPUT
 ***EXECUTE OUTPUT ON LOCAL FILE 'B2'
*RDY*
```

EQUITY OIL CO./U.S. DEPARTMENT OF ENERGY

PAGE- 1
DATE- 03/13/80
TIME- 11.14.05.

BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

REPORT PERIOD

FROM TO

DETAIL SUMMARY OF DAYS INCLUDED IN THIS REPORT

DATA COLLECTED FOR FEBRUARY 1, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 2, 1980 ENDS AT 22:31:52
DATA COLLECTED FOR FEBRUARY 3, 1980 ENDS AT 22:31:52
DATA COLLECTED FOR FEBRUARY 4, 1980 ENDS AT 21:00:00
DATA COLLECTED FOR FEBRUARY 5, 1980 ENDS AT 21:20:25
DATA COLLECTED FOR FEBRUARY 6, 1980 ENDS AT 22:53:33
DATA COLLECTED FOR FEBRUARY 7, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 8, 1980 ENDS AT 23:59:33
DATA COLLECTED FOR FEBRUARY 9, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 10, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 11, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 12, 1980 ENDS AT 08:00:00
DATA COLLECTED FOR FEBRUARY 13, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 14, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 15, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 16, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 17, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 18, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 19, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 20, 1980 ENDS AT 16:07:27
DATA COLLECTED FOR FEBRUARY 21, 1980 ENDS AT 23:59:59
DATA COLLECTED FOR FEBRUARY 22, 1980 ENDS AT 20:00:00
DATA COLLECTED FOR FEBRUARY 23, 1980 ENDS AT 20:00:00
DATA COLLECTED FOR FEBRUARY 24, 1980 ENDS AT 20:00:00
DATA COLLECTED FOR FEBRUARY 25, 1980 ENDS AT 20:00:00
DATA COLLECTED FOR FEBRUARY 26, 1980 ENDS AT 20:00:00
DATA COLLECTED FOR FEBRUARY 27, 1980 ENDS AT 23:59:05

*** TABLE OF ENTHALPIES ****

1	1175.73
2	1176.64
3	1179.99
4	1175.47
5	1175.85
6	1175.67
7	1175.65
8	1178.75
9	1226.75

EQUITY OIL CO./U.S. DEPARTMENT OF ENERGY

BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

REPORT PERIOD

FROM 02/01/80 TO 02/29/80

INJECTION

WELL	BBLS/DAY	CUM.BBLS 10**2	BTU/DAY 10**6	CUM.BTU 10**8	CTD.BBLS 10**2	CTD.BTU 10**8
1/BX-31	193.12	42.5	227.1	5.0	42.49	42.49
2/BX-16	227.51	61.4	267.7	7.2	61.43	61.43
3/BX-30	85.29	23.0	100.6	2.7	23.03	23.03
4/BX-17	179.96	48.6	211.5	5.7	48.59	48.59
5/BX-32	226.36	61.1	266.2	7.2	61.12	61.12
6/BX-24	230.44	62.2	270.9	7.3	62.22	62.22
7/BX-23	146.14	39.5	171.8	4.6	39.46	39.46
8/BX-33	349.64	94.4	412.1	11.1	94.40	94.40
TOTAL	1638.47	432.7	1928.0	50.9	432.7	50.9

INJECTION DOWNTIME

WELL NO.	1	2	3	4	5	6	7	8
DAYS BELOW SET LIMIT	7	2	2	2	2	2	2	2
SET LIMIT IN BBLS/DAY	0.686	0.686	0.686	0.686	0.686	0.686	0.686	0.686
CUMULATIVE DOWNTIME TO-DATE	143	138	138	138	138	138	138	138
TOTAL INJECTION DAYS TO-DATE	22	27	27	27	27	27	27	27

PRODUCTION

	WATER			OIL		
	BBL/DAY	BBL CUM(10**2)	BBL CTD(10**3)	BBL/DAY	BBL CUM(10**2)	BBL CTD(10**2)
TEST SEP	149.4	43.3	4.33	0.0	0.0	0.00
FWKO	800.7	232.2	23.22	0.0	0.0	0.00
TOTAL	950.2	275.5	27.6	0.0	0.0	0.0

	GAS		
	MCF/DAY	MCF CUM(10**2)	MCF CTD(10**3)
TEST SEP	80.4	23.3	2.33
FWKO	311.3	90.3	9.03
TOTAL	391.7	113.6	11.4
INPUT	401.0	116.3	11.63
NET	-9.3	-2.7	-0.3

***** KEY FOR GAS PRODUCED *****

NET(+)=FORMATION GAS PRODUCED

NET(-)=GAS LIFT + GAS LOST

BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

REPORT PERIOD

FROM 02/01/80 TO 02/29/80

STEAM GENERATION

	FEED-WATER			FUEL					
	BPD 10**2	BBL CUM 10**2	BBL CTD 10**3	MCFPD	CUM.MCF	CTD.MCF	BTU/DAY (10**6)	CUM.BTU (10**8)	CTD.BTU (10**8)
STEAM GEN.1	10.6	275.6	27.56	227.1	5904.5	11.63	227.1	59.0	59.05
STEAM GEN.2	11.7	303.3	30.33	254.6	6618.6	5904.51	254.6	66.2	66.19
TOTAL	22.3	578.9	57.9	481.7	12523.1	12523.1	481.7	125.2	125.2

SUPERHEATER

TOTAL-STEAM			FUEL					
LBS/DAY (10**3)	CUM.LBS (10**4)	CTD.LBS (10**4)	MCFPD	CUM.MCF	CTD.MCF	BTU/DAY (10**6)	CUM.BTU (10**8)	CTD.BTU (10**8)
0.0	0.0	0.00	2.5	65.5	65.46	0.0	0.0	5.00

/----TOTAL FACILITY FUEL FLOW----/

MCF/DAY	CUM.MCF	CTD.MCF
581.3	65.5	15113.98

EQUITY OIL CO./U.S. DEPARTMENT OF ENERGY

PAGE- 4
DATE- 03/13/80
TIME- 11.14.05.

BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

REPORT PERIOD

FROM 02/01/80 TO 02/29/80

OPERATING PRESSURES(PSIG)

INJECTION WELL NO.	DAILY AVG.	PERIOD AVG.	MINIMUM	MAXIMUM	AVERAGE TO-DATE
1/BX-31	1391.6	1330.6	1202.00	1394.22	733.2
2/BX-16	1373.4	1332.4	1265.11	1377.12	666.2
3/BX-30	1304.8	1110.6	323.86	1335.25	555.3
4/BX-17	1396.7	1298.1	855.43	1423.78	649.1
5/BX-32	1389.3	1337.1	1231.14	1394.32	668.5
6/BX-24	1392.8	1346.4	1274.22	1396.56	673.2
7/BX-23	1393.3	1341.1	1207.57	1399.71	670.5
8/BX-33	1330.5	1191.3	778.80	1340.10	595.7
MONITOR WELL NO.					
1/BX-29	3.9	3.5	0.00	3.88	3.5
2/BX-34	0.0	0.0	0.00	0.00	3.5
3/BX-35	8.9	0.0	0.00	0.00	3.5
SUPERHTR DISCHG.	34.9	35.9	34.85	36.39	1.3

OPERATING TEMPERATURES (DEG.F)

	DAILY AVG.	PERIOD AVG.	MINIMUM	MAXIMUM	AVERAGE TO-DATE
SUPERHTR DIS.	378.7	379.1	378.69	379.16	13.5
STM.GEN.1 STK.	429.8	382.1	160.70	517.10	13.6
STM.GEN.2 STK.	418.5	369.6	79.10	450.40	13.1
SUPERHTR.STK.	58.3	63.3	49.42	84.87	2.2
INJ.WELL 1/BX-31	434.2	432.5	420.54	436.89	15.4
INJ.WELL 2/BX-16	445.2	433.8	0.00	475.00	14.9
INJ.WELL 3/BX-30	427.7	345.8	51.66	441.77	12.3
INJ.WELL 4/BX-17	473.3	422.9	63.71	493.80	15.0
INJ.WELL 5/BX-32	484.4	477.9	464.18	487.10	17.0
INJ.WELL 6/BX-24	392.0	377.6	367.61	404.53	13.4
INJ.WELL 7/BX-23	568.3	563.3	549.69	569.09	20.0
INJ.WELL 8/BX-33	558.2	534.9	456.54	561.37	19.0
PROD.WELL 0/BX-19	51.7	38.9	19.69	52.28	1.4
PROD.WELL 1/BX-26	48.2	47.2	44.25	50.59	1.7
PROD.WELL 2/BX-20	32.7	28.8	16.37	34.45	1.0
PROD.WELL 3/BX-14	94.7	96.4	92.80	99.54	3.4
PROD.WELL 4/BX-21	47.8	46.2	40.06	57.27	1.6

EQUITY OIL CO./U.S. DEPARTMENT OF ENERGY

PAGE- 5
DATE- 03/13/80
TIME- 11.14.05.

BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

REPORT PERIOD

FROM 02/01/80 TO 02/29/80

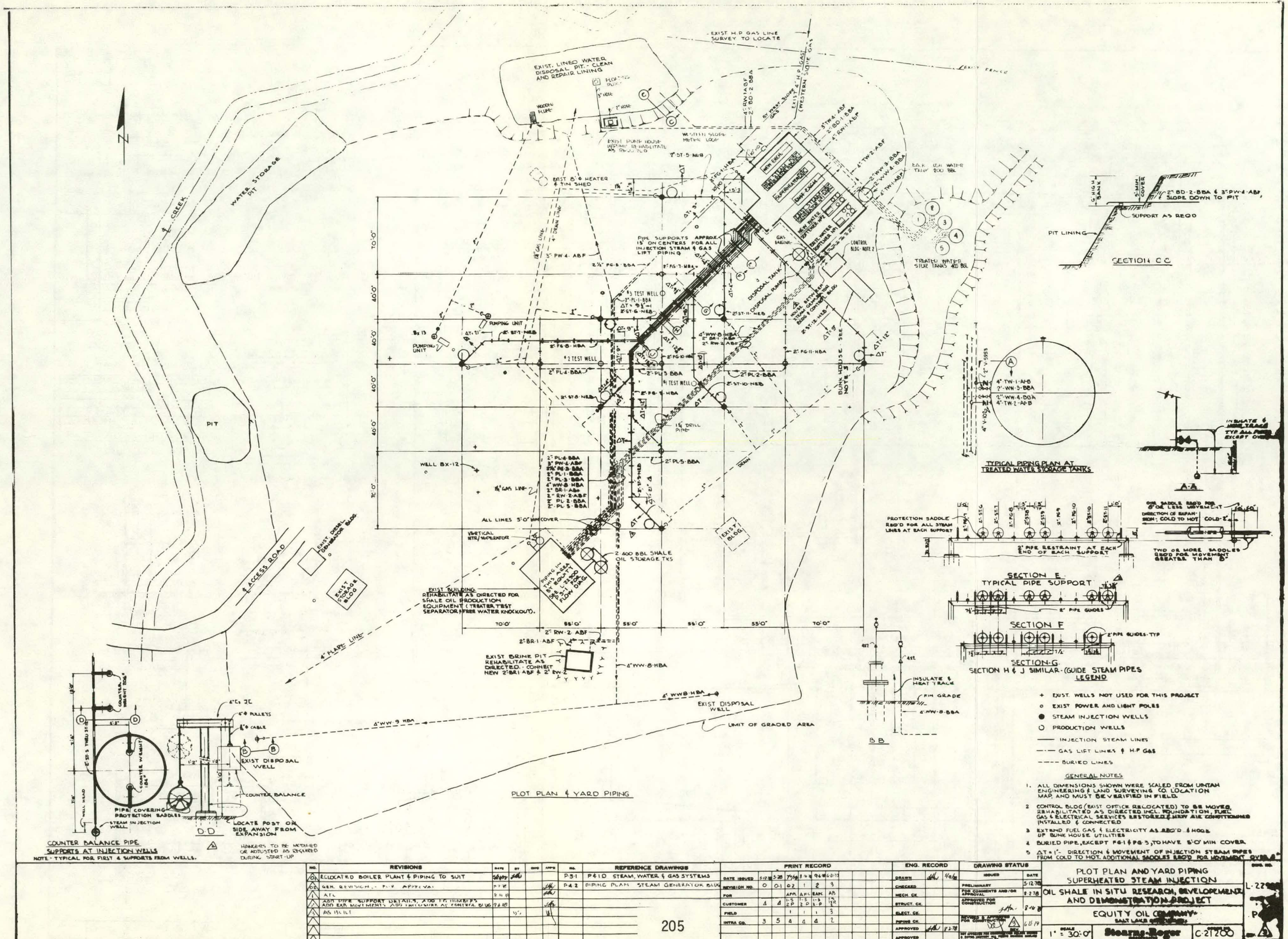
TEMPERATURE OBSERVATION WELLS

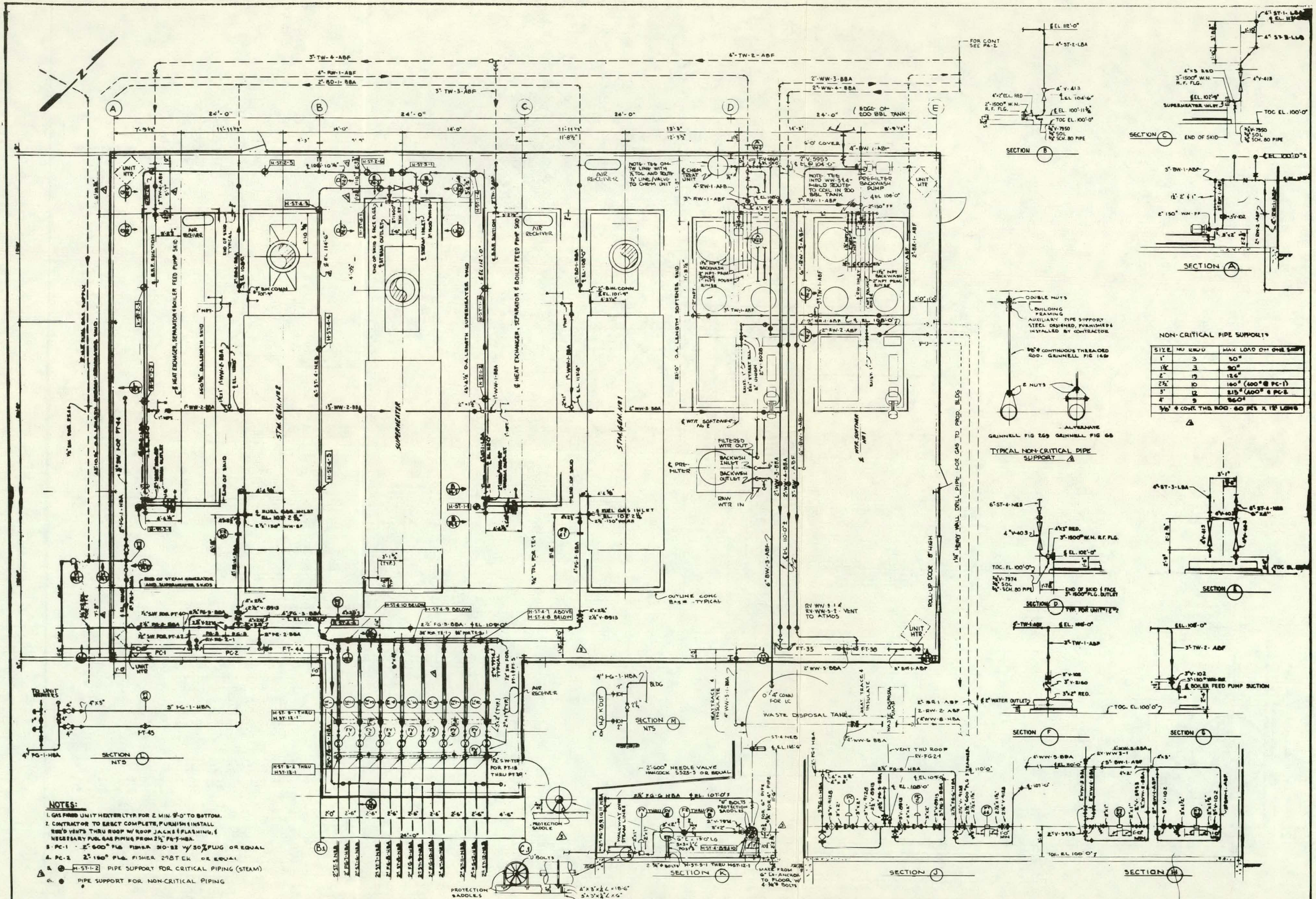
	/-DAILY AVG. TEMPERATURE-/			/-PERIOD AVG.TEMPERATURE-/			/--MINIMUM TEMPERATURE--/			/--MAXIMUM TEMPERATURE--/		
DEPTH	NO.1	NO.2	NO.3	NO.1	NO.2	NO.3	NO.1	NO.2	NO.3	NO.1	NO.2	NO.3
450.0	57.5	116.5	79.2	57.3	91.8	76.9	57.02	80.33	73.92	57.47	117.26	79.26
500.0	57.9	100.5	79.2	57.6	86.3	77.9	57.34	82.13	76.49	57.91	101.84	79.55
600.0	61.4	113.0	104.0	61.2	99.9	100.3	61.08	84.60	97.23	61.38	113.46	104.13
700.0	67.4	106.3	148.9	67.5	95.5	139.3	67.33	88.89	131.21	67.83	106.83	149.37
760.0	66.1	176.6	107.8	65.8	142.1	104.4	65.50	107.60	101.21	66.14	180.11	107.91
780.0	65.6	94.8	118.3	65.2	93.0	115.0	64.76	87.89	111.71	65.60	97.65	118.48
S-T-A-R-T---U-P-P-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E												
800.0	70.4	160.2	83.4	69.3	116.6	82.7	68.21	90.45	81.84	70.44	160.89	83.43
820.0	94.6	106.9	85.0	89.6	106.5	83.8	85.94	105.78	82.11	94.73	106.99	85.19
840.0	126.0	99.7	83.1	114.7	98.6	82.2	106.74	97.46	81.44	126.45	99.76	83.10
860.0	232.4	99.6	82.3	210.9	99.4	82.4	194.00	99.15	82.26	233.29	99.63	82.83
E-N-D---U-P-P-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E												
880.0	387.7	101.9	84.0	352.2	101.2	83.9	333.87	100.06	83.78	389.04	101.92	84.00
900.0	100.4	99.7	86.2	93.8	99.3	87.0	83.76	98.03	85.82	100.80	99.72	88.72
920.0	60.6	104.8	88.1	50.5	105.7	88.1	31.27	104.70	87.83	61.44	107.47	88.24
940.0	80.1	105.3	94.4	76.5	104.2	94.0	72.44	102.96	93.56	85.72	105.35	94.42
960.0	93.1	114.5	96.1	97.9	113.4	96.7	92.37	111.74	96.00	107.59	114.60	97.56
S-T-A-R-T---P-R-O-D-U-C-T-I-O-N---Z-O-N-E												
980.0	93.4	175.1	101.1	98.4	171.0	100.0	93.28	164.79	98.24	108.00	175.77	101.16
1000.0	90.1	217.6	107.9	92.2	215.1	108.6	88.83	211.59	107.86	103.99	217.75	109.39
1020.0	135.0	196.7		159.1	195.4		130.50	192.04		221.46	196.77	
1040.0	106.5	132.2	65.2	108.1	131.6	73.3	100.36	128.54	64.52	120.18	132.80	94.86
1060.0	93.4	93.5	118.6	89.6	93.4	111.8	85.69	92.80	96.29	93.68	93.55	123.40
1080.0	92.4	56.5	97.7	88.7	56.4	129.5	85.89	56.31	96.03	92.49	56.52	208.85
1100.0	93.3	57.4	161.2	90.2	57.3	158.8	85.78	57.21	155.43	93.63	57.39	161.37
1120.0	99.2	59.4	122.4	97.8	59.4	133.1	94.85	59.39	117.96	104.62	59.50	156.64
1140.0	85.4	62.1	74.7	79.2	62.1	85.6	71.72	61.96	74.66	85.64	62.13	101.68
E-N-D---P-R-O-D-U-C-T-I-O-N---Z-O-N-E												
1160.0	89.6	64.2	95.2	88.3	64.2	95.6	83.85	64.14	91.46	91.91	64.24	108.22
1180.0	68.9	66.8	60.1	79.7	66.5	59.7	68.73	66.26	59.39	105.89	66.83	60.10
1200.0	105.4	72.3	64.2	119.2	70.6	63.9	104.80	68.96	63.57	160.40	72.37	64.18
1220.0	84.2	113.0	65.6	85.6	102.1	65.4	80.63	86.36	65.22	90.35	113.91	65.57
1240.0	103.2	150.5	67.6	92.6	133.2	67.4	81.03	105.56	67.23	104.65	151.94	67.56
S-T-A-R-T---L-O-W-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E												
1260.0	93.8	345.6	69.8	85.2	304.6	69.7	79.04	195.60	69.53	94.79	355.28	69.83
1280.0	126.3	356.8	72.2	111.3	308.6	72.0	84.50	217.34	71.81	126.98	361.43	72.25
1300.0	118.5	106.7	79.5	103.3	99.1	78.2	81.90	77.71	77.17	120.18	115.27	79.54
1320.0	96.2	81.4	148.7	90.7	78.4	103.7	84.20	72.78	88.66	97.31	81.61	150.56
1340.0	94.3	71.0	160.5	89.0	73.0	109.4	81.69	70.97	85.57	94.64	74.24	163.21
1360.0	89.0	77.4		88.5	73.8		85.57	71.82		90.50	77.49	
E-N-D---L-O-W-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E												

***** KEY TO OBSERVATION WELLS *****

OBS. WELL NO. 1=BX-29
OBS. WELL NO. 2=BX-34
OBS. WELL NO. 3=BX-35

APPENDIX "F"


PLOT PLAN & YARD PIPING
EXIST. LINED WATER DISPOSAL PIT - CLEAN AND REPAIR LINING
EXIST. H.P. GAS LINE SURVEY TO LOCATE
WATER STORAGE PIT
CREEK
PIT
ACCESS ROAD
EXIST STORAGE BLDG
EXIST 8'⌀ HEATER & TIN SHED
EXIST PUMP HOUSE
PIPE SUPPORTS APPROX. 15' ON CENTERS FOR ALL INJECTION STEAM & GAS LIFT PIPING
DISPOSAL TANK
DISPOSAL PUMP
CONTROL BLDG - NOTE 2
BUNK HOUSE - SEE NOTE 3
TREATED WATER STOR TANKS 400 BBL
WELL BX-12
PUMPING UNIT
ALL LINES 5'0" MIN COVER
2-400 BBL SHALE OIL STORAGE TKS
EXIST BUILDING REHABILITATE AS DIRECTED FOR SHALE OIL PRODUCTION EQUIPMENT (TREATER TEST SEPARATOR, FREE WATER KNOCKOUT)
EXIST BRINE PIT REHABILITATE AS DIRECTED - CONNECT NEW 2" BR-1-ABF & 2" RW
EXIST DISPOSAL WELL
LIMIT OF GRADED AREA
4" WW-9-HBA
4" PLAPE LINE
SECTION C-C
PIT LINING
SUPPORT AS REQ'D
TYPICAL PIPING PLAN AT TREATED WATER STORAGE TANKS
A-A
SECTION E
TYPICAL PIPE SUPPORT
PROTECTION SADDLE REQ'D FOR ALL STEAM LINES AT EACH SUPPORT
2" PIPE RESTRAINT AT EACH END OF EACH SUPPORT
TWO OR MORE SADDLES REQ'D FOR MOVEMENT GREATER THAN 6"
SECTION F
2" PIPE GUIDES - TYP
SECTION-G
SECTION H & J SIMILAR - (GUIDE STEAM PIPES
B-B
INSULATE & HEAT TRACE
FIN GRADE
COUNTER BALANCE PIPE SUPPORTS AT INJECTION WELLS
NOTE - TYPICAL FOR FIRST 4 SUPPORTS FROM WELLS.
PIPE COVERING PROTECTION SADDLES
STEAM INJECTION WELL
COUNTER BALANCE
LOCATE POST ON SIDE AWAY FROM EXPANSION
HANGERS TO BE MODIFIED OR ADJUSTED AS REQUIRED DURING START-UP
D-D
EXIST DISPOSAL WELL
LEGEND
+ EXIST. WELLS NOT USED FOR THIS PROJECT
o EXIST POWER AND LIGHT POLES
● STEAM INJECTION WELLS
O PRODUCTION WELLS
—— INJECTION STEAM LINES
-·- GAS LIFT LINES & H.P GAS
---- BURIED LINES
GENERAL NOTES
1. ALL DIMENSIONS SHOWN WERE SCALED FROM UINTAH ENGINEERING & LAND SURVEYING CO. LOCATION MAP, AND MUST BE VERIFIED IN FIELD.
2 CONTROL BLDG (EXIST OFFICE RELOCATED) TO BE MOVED, REHABILITATED AS DIRECTED INCL. FOUNDATION, FUEL GAS & ELECTRICAL SERVICES RESTORED & NEW AIR CONDITIONER INSTALLED & CONNECTED
3 EXTEND FUEL GAS & ELECTRICITY AS REQ'D & HOOK UP BUNK HOUSE UTILITIES
4 BURIED PIPE, EXCEPT FG-1 & PG-3, TO HAVE 5'-0" MIN COVER
5 ΔT = 1" - DIRECTION & MOVEMENT OF INJECTION STEAM PIPES FROM COLD TO HOT. ADDITIONAL SADDLES REQ'D FOR MOVEMENT OVER 6"
REVISIONS
0 RELOCATED BOILER PLANT & PIPING TO SUIT
0.2 GEN. REVISION - FOR APPROVAL
1 AFC
2 ADD PIPE SUPPORT DETAILS, ADD FG NUMBERS ADD EXP. MOVEMENTS ADD INCLOSURE AT CONTROL BLDG
3 AS BUILT
REFERENCE DRAWINGS
P-5-1 P&ID STEAM, WATER & GAS SYSTEMS
P-4-2 PIPING PLAN STEAM GENERATOR BLDG
PRINT RECORD
ENG. RECORD
DRAWING STATUS
PRELIMINARY 5-12-78
FOR COMMENTS AND/OR APPROVAL 8-2-78
APPROVED FOR CONSTRUCTION 8-16-78
REVISED & APPROVED FOR CONSTRUCTION 6-11-79
PLOT PLAN AND YARD PIPING
SUPERHEATED STEAM INJECTION
OIL SHALE IN SITU RESEARCH, DEVELOPMENT AND DEMONSTRATION PROJECT
EQUITY OIL COMPANY
SALT LAKE CITY, UTAH
SCALE 1" = 30'-0"
Stearns-Roger
C-21200



NON-CRITICAL PIPE SUPPORTS

SIZE	NO REQ'D	MAX LOAD ON ONE SUPPORT
1"	3	50#
1½"	3	90#
2"	19	126#
2½"	10	160# (400# @ PC-1)
3"	12	215# (400# @ PC-2
4"	9	360#
3/8" ϕ CONT. THD. ROD - 60 PCS X 12' LONG		

NOTES:

1. GAS FIRED UNIT HEATER (TYP. FOR 2 MIN. 8'-0" TO BOTTOM.
2. CONTRACTOR TO ERECT COMPLETE, FURNISH & INSTALL REQ'D VENTS THRU ROOF W/ ROOF JACKS & FLASHING, & NECESSARY FUEL GAS PIPING FROM 2½" FG-9-HBA.
3. PC-1 · 2"-600# FLG FISHER 310-32 W/ 30% PLUG OR EQUAL
4. PC-2 2"-150# FLG. FISHER 298T EK OR EQUAL
5. H-ST-1-2 PIPE SUPPORT FOR CRITICAL PIPING (STEAM)
6. ● PIPE SUPPORT FOR NON-CRITICAL PIPING

NO.	REVISIONS	DATE	BY	CHK'D	APP'D
0-1	FOR APPROVAL	7-7-78	JJS		
1	UPDATED, ADDED PIPING DETAILS, REVISE ST-1,2,3, FG-1-2,3,4,6				
2	ADD NOTES 5 & 6, ADD NON-CRITICAL PIPE SUPPORTS, NON CRITICAL PS TYP DETAIL & TABLE OF PS REQ'D	8-11-78			
	ADD CRITICAL P.S. ON 2" ST-5 THRU 2" ST-12				

REFERENCE DRAWINGS

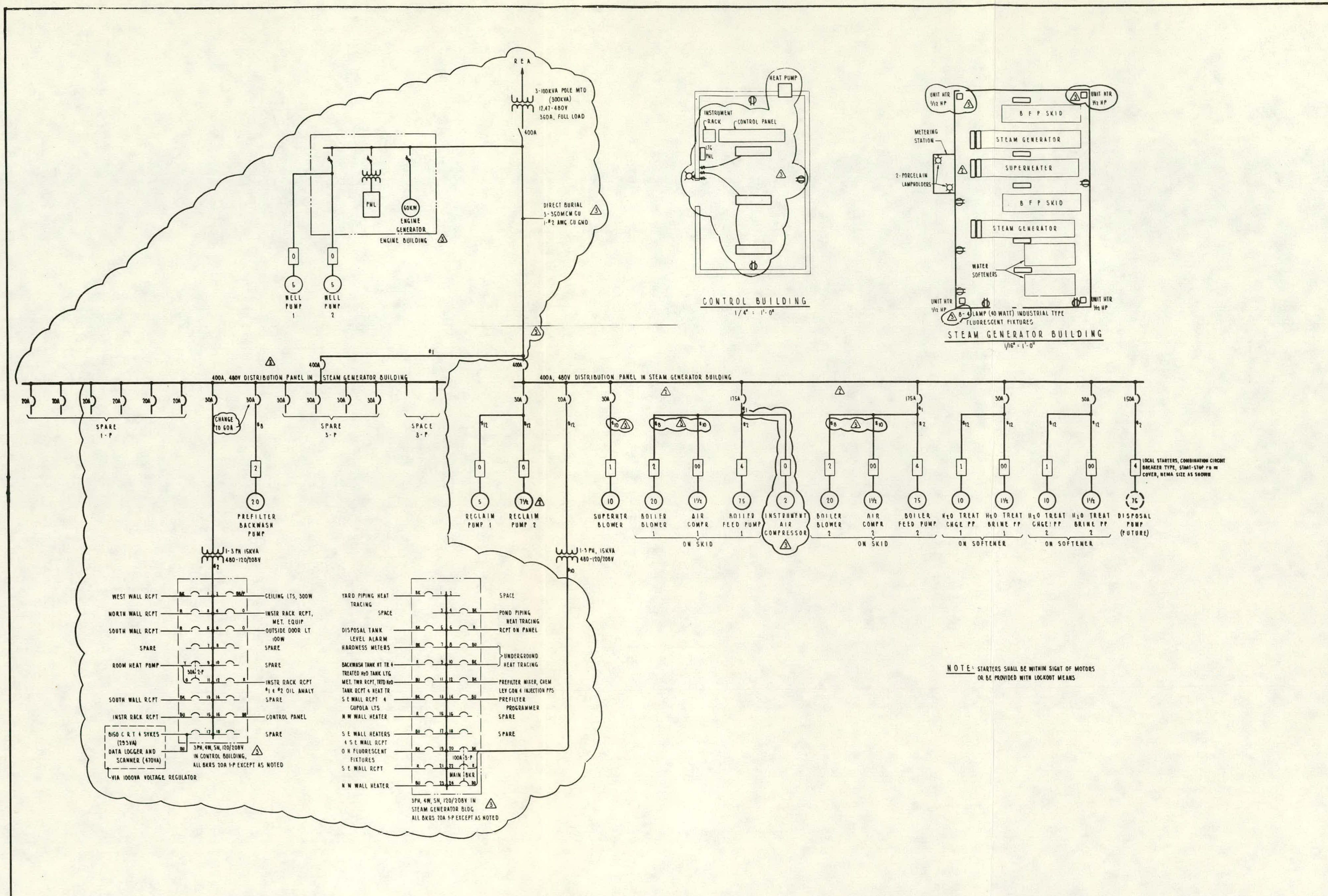
PRINT RECORD

DATE ISSUED							
REVISION NO.	0	0-1	1	2	3	4	5
FOR		APP	AFC	RAFC	RAFC	RAFC	RAFC
CUSTOMER	✓						

ENG. RECORD: DRAWN RAF; CHECKED; MECH. CK.; STRUCT. CK.

DRAWING STATUS: PRELIMINARY; FOR COMMENTS AND/OR APPROVAL; APPROVED FOR CONSTRUCTION

PIPING PLAN
STEAM GENERATOR BUILDING
OIL SHALE IN SITU RESEARCH, DEVELOPMENT, AND DEMONSTRATION PROJECT



NO.	REVISIONS	DATE	BY	CH'D	APP'D
0	REMOVED PNL AT DIESEL GEN. BLDG, "HOLD" ON CONTROL BLDG LIGHTING	7-7-78	W P B		
1	REMOVED "HOLD", ADDED NOTE, CONTROL BUILDING	7-13-78	W P B		
2	RECLAIM PP 2 WAS 5 HP, ADDED 2 UNIT HTRS, PREFILTER BACKWASH PP, TAP NOTE	11-28-78	W P B		
3	REDRAWN TO INCLUDE FIELD ADDITIONS	4-3-79	W P B		

REFERENCE DRAWINGS

207

PRINT RECORD					
DATE ISSUED	7/7/78	7-14-78	11/28/78	4-4-79	6/1/79
REVISION NO.	0	1	2	3	3
FOR	APPL	AFC	RAFC	As Bilt	AB
CUSTOMER	2-P 1-S	2-P 1-S	2-P 1-S	2	1S 1RR
FIELD	1	1	1	2	
INTRA CO.	4	4	4	2	

ENG. RECORD		
DRAWN	W P B	6-23-78
CHECKED		6/27/78
MECH. CK.		
STRUCT. CK.		
ELECT. CK.		6-29-78
PIPING CK.		
APPROVED		
APPROVED		

DRAWING STATUS	
ISSUED	DATE
PRELIMINARY	
FOR COMMENTS AND/OR APPROVAL	7/7/78
APPROVED FOR CONSTRUCTION	8-14-78
REVISED & APPROVED FOR CONSTRUCTION	

ELECTRICAL
ONE LINE DIAGRAM & MISCELLANEOUS PLANS
OIL SHALE IN SITU RESEARCH, DEVELOPMENT AND DEMONSTRATION PROJECT
EQUITY OIL COMPANY
SALT LAKE CITY, UTAH

SCALE: AS SHOWN
Stearns-Roger INCORPORATED
ORDER NO. C-21200
DWG. NO. L-22900
SHEET NO. E2-1
REV. 3

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APPENDIX "G"

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EQUITY OIL CO./U.S. DEPARTMENT OF ENERGY

BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

Appendix "G"

REPORT PERIOD

FROM TO

DETAIL SUMMARY OF DAYS INCLUDED IN THIS REPORT

DATA COLLECTED FOR SEPTEMBER 18, 1979
DATA COLLECTED FOR SEPTEMBER 19, 1979
DATA COLLECTED FOR SEPTEMBER 20, 1979
DATA COLLECTED FOR SEPTEMBER 21, 1979
DATA COLLECTED FOR SEPTEMBER 22, 1979
DATA COLLECTED FOR SEPTEMBER 23, 1979
DATA COLLECTED FOR SEPTEMBER 24, 1979
DATA COLLECTED FOR SEPTEMBER 25, 1979
DATA COLLECTED FOR SEPTEMBER 26, 1979
DATA COLLECTED FOR SEPTEMBER 27, 1979
DATA COLLECTED FOR SEPTEMBER 28, 1979
DATA COLLECTED FOR SEPTEMBER 29, 1979
DATA COLLECTED FOR SEPTEMBER 30, 1979
DATA COLLECTED FOR OCTOBER 1, 1979
DATA COLLECTED FOR OCTOBER 2, 1979
DATA COLLECTED FOR OCTOBER 3, 1979
DATA COLLECTED FOR OCTOBER 4, 1979
DATA COLLECTED FOR OCTOBER 5, 1979
DATA COLLECTED FOR OCTOBER 6, 1979
DATA COLLECTED FOR OCTOBER 9, 1979
DATA COLLECTED FOR OCTOBER 10, 1979
DATA COLLECTED FOR OCTOBER 11, 1979
DATA COLLECTED FOR OCTOBER 12, 1979
DATA COLLECTED FOR OCTOBER 13, 1979
DATA COLLECTED FOR OCTOBER 14, 1979
DATA COLLECTED FOR OCTOBER 15, 1979
DATA COLLECTED FOR OCTOBER 16, 1979
DATA COLLECTED FOR OCTOBER 17, 1979
DATA COLLECTED FOR OCTOBER 18, 1979
DATA COLLECTED FOR OCTOBER 19, 1979
DATA COLLECTED FOR OCTOBER 20, 1979
DATA COLLECTED FOR OCTOBER 21, 1979
DATA COLLECTED FOR OCTOBER 22, 1979
DATA COLLECTED FOR OCTOBER 23, 1979
DATA COLLECTED FOR OCTOBER 24, 1979
DATA COLLECTED FOR OCTOBER 26, 1979
DATA COLLECTED FOR OCTOBER 27, 1979
DATA COLLECTED FOR OCTOBER 28, 1979
DATA COLLECTED FOR OCTOBER 29, 1979
DATA COLLECTED FOR OCTOBER 30, 1979
DATA COLLECTED FOR OCTOBER 31, 1979
DATA COLLECTED FOR NOVEMBER 1, 1979
DATA COLLECTED FOR NOVEMBER 2, 1979
DATA COLLECTED FOR NOVEMBER 3, 1979
DATA COLLECTED FOR NOVEMBER 4, 1979
DATA COLLECTED FOR NOVEMBER 5, 1979
DATA COLLECTED FOR NOVEMBER 6, 1979
DATA COLLECTED FOR NOVEMBER 7, 1979
DATA COLLECTED FOR NOVEMBER 8, 1979
DATA COLLECTED FOR NOVEMBER 10, 1979
DATA COLLECTED FOR NOVEMBER 11, 1979
DATA COLLECTED FOR NOVEMBER 12, 1979

BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

REPORT PERIOD

FROM 09/18/79 TO 02/29/80

DATA COLLECTED FOR NOVEMBER 13, 1979
DATA COLLECTED FOR NOVEMBER 14, 1979
DATA COLLECTED FOR NOVEMBER 15, 1979
DATA COLLECTED FOR NOVEMBER 16, 1979
DATA COLLECTED FOR NOVEMBER 17, 1979
DATA COLLECTED FOR NOVEMBER 18, 1979
DATA COLLECTED FOR NOVEMBER 20, 1979
DATA COLLECTED FOR NOVEMBER 21, 1979
DATA COLLECTED FOR NOVEMBER 22, 1979
DATA COLLECTED FOR NOVEMBER 23, 1979
DATA COLLECTED FOR NOVEMBER 24, 1979
DATA COLLECTED FOR NOVEMBER 25, 1979
DATA COLLECTED FOR NOVEMBER 26, 1979
DATA COLLECTED FOR NOVEMBER 27, 1979
DATA COLLECTED FOR NOVEMBER 28, 1979
DATA COLLECTED FOR NOVEMBER 29, 1979
DATA COLLECTED FOR NOVEMBER 30, 1979
DATA COLLECTED FOR DECEMBER 1, 1979
DATA COLLECTED FOR DECEMBER 2, 1979
DATA COLLECTED FOR DECEMBER 3, 1979
DATA COLLECTED FOR DECEMBER 4, 1979
DATA COLLECTED FOR DECEMBER 5, 1979
DATA COLLECTED FOR DECEMBER 6, 1979
DATA COLLECTED FOR DECEMBER 7, 1979
DATA COLLECTED FOR DECEMBER 8, 1979
DATA COLLECTED FOR DECEMBER 9, 1979
DATA COLLECTED FOR DECEMBER 10, 1979
DATA COLLECTED FOR DECEMBER 11, 1979
DATA COLLECTED FOR DECEMBER 12, 1979
DATA COLLECTED FOR DECEMBER 13, 1979
DATA COLLECTED FOR DECEMBER 14, 1979
DATA COLLECTED FOR DECEMBER 15, 1979
DATA COLLECTED FOR DECEMBER 16, 1979
DATA COLLECTED FOR DECEMBER 17, 1979
DATA COLLECTED FOR DECEMBER 18, 1979
DATA COLLECTED FOR DECEMBER 19, 1979
DATA COLLECTED FOR DECEMBER 20, 1979
DATA COLLECTED FOR JANUARY 1, 1980
DATA COLLECTED FOR JANUARY 2, 1980
DATA COLLECTED FOR JANUARY 3, 1980
DATA COLLECTED FOR JANUARY 4, 1980
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DATA COLLECTED FOR JANUARY 13, 1980
DATA COLLECTED FOR JANUARY 14, 1980
DATA COLLECTED FOR JANUARY 15, 1980
DATA COLLECTED FOR JANUARY 16, 1980
DATA COLLECTED FOR JANUARY 17, 1980

EQUITY OIL CO./U.S. DEPARTMENT OF ENERGY

BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

REPORT PERIOD

FROM 09/18/79 TO 02/29/80

DATA COLLECTED FOR JANUARY 18, 1980
DATA COLLECTED FOR JANUARY 19, 1980
DATA COLLECTED FOR JANUARY 20, 1980
DATA COLLECTED FOR JANUARY 21, 1980
DATA COLLECTED FOR JANUARY 22, 1980
DATA COLLECTED FOR JANUARY 24, 1980
DATA COLLECTED FOR JANUARY 25, 1980
DATA COLLECTED FOR JANUARY 26, 1980
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DATA COLLECTED FOR JANUARY 28, 1980
DATA COLLECTED FOR JANUARY 29, 1980
DATA COLLECTED FOR JANUARY 30, 1980
DATA COLLECTED FOR JANUARY 31, 1980
DATA COLLECTED FOR FEBRUARY 2, 1980
DATA COLLECTED FOR FEBRUARY 3, 1980
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DATA COLLECTED FOR FEBRUARY 6, 1980
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DATA COLLECTED FOR FEBRUARY 19, 1980
DATA COLLECTED FOR FEBRUARY 20, 1980
DATA COLLECTED FOR FEBRUARY 22, 1980
DATA COLLECTED FOR FEBRUARY 23, 1980
DATA COLLECTED FOR FEBRUARY 24, 1980
DATA COLLECTED FOR FEBRUARY 25, 1980

*** TABLE OF ENTHALPIES ****

1	1182.00
2	1183.92
3	1188.25
4	1181.17
5	1183.81
6	1185.42
7	1182.01
8	1192.14
9	1224.16

EQUITY OIL CO./U.S. DEPARTMENT OF ENERGY

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FROM 09/18/79 TO 02/29/80

INJECTION

WELL	BBLS/DAY	CUM.BBLS 10**2	BTU/DAY 10**6	CUM.BTU 10**8	CTD.BBLS 10**2	CTD.BTU 10**8
1/BX-31	164.70	219.0	68.1	90.6	219.05	219.05
2/BX-16	170.94	234.2	70.8	97.0	234.19	234.19
3/BX-30	46.88	55.8	19.5	23.2	55.79	55.79
4/BX-17	146.34	196.1	60.5	81.1	196.10	196.10
5/BX-32	215.73	293.4	89.4	121.6	293.39	293.39
6/BX-24	149.69	202.1	62.1	83.8	202.08	202.08
7/BX-23	250.33	340.4	103.6	140.8	340.44	340.44
8/BX-33	356.18	491.5	148.6	205.1	491.53	491.53
TOTAL	1500.80	2032.6	622.6	843.3	2032.6	843.3

INJECTION DOWNTIME

WELL NO.	1	2	3	4	5	6	7	8
DAYS BELOW SET LIMIT	32	28	46	31	29	30	29	27
SET LIMIT IN BBLS/DAY	0.686	0.686	0.686	0.686	0.686	0.686	0.686	0.686
CUMULATIVE DOWNTIME TO-DATE	32	28	46	31	29	30	29	27
TOTAL INJECTION DAYS TO-DATE	133	137	119	134	136	135	136	138

PRODUCTION

	WATER			OIL		
	BBL/DAY	BBL CUM(10**2)	BBL CTD(10**3)	BBL/DAY	BBL CUM(10**2)	BBL CTD(10**2)
TEST SEP	148.5	245.0	24.50	0.0	0.0	0.00
FWKO	731.0	1206.1	120.61	0.0	0.0	0.00
TOTAL	879.5	1451.1	145.1	0.0	0.0	0.0

	GAS		
	MCF/DAY	MCF CUM(10**2)	MCF CTD(10**3)
TEST SEP	85.8	141.6	14.16
FWKO	244.7	403.8	40.38
TOTAL	330.6	545.4	54.5
INPUT	393.4	649.0	64.90
NET	-62.8	-103.6	-10.4

***** KEY FOR GAS PRODUCED *****
NET(+)=FORMATION GAS PRODUCED
NET(-)=GAS LIFT + GAS LOST

FLUID PRODUCTION
PRODUCTION SURVEILLANCE MONITOR

WELL NO.	BBL/DAY	CUM.BBL (10**2)	CTD.BBL (10**2)
0/BX-19	312.9	516.3	516.25
1/BX-26	323.1	533.1	533.12
2/BX-20	201.8	333.0	333.04
3/BX-14	238.1	392.9	392.85
4/BX-21	239.8	395.7	395.75

EQUITY OIL CO./U.S. DEPARTMENT OF ENERGY

BX IN SITU OIL SHALE PROJECT
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STEAM GENERATION

	FEED-WATER			FUEL					
	BPD 10**2	BBL CUM 10**2	BBL CTD 10**3	MCFPD	CUM.MCF	CTD.MCF	BTU/DAY (10**6)	CUM.BTU (10**8)	CTD.BTU (10**8)
STEAM GEN.1	12.2	1676.5	167.65	179.9	24650.8	64.90	179.9	246.5	246.51
STEAM GEN.2	12.8	1753.4	175.34	269.6	36940.3	24650.77	269.6	369.4	369.40
TOTAL	25.0	3429.9	343.0	449.6	61591.1	61591.1	449.6	615.9	615.9

SUPERHEATER

TOTAL-STEAM			FUEL					
LBS/DAY (10**3)	CUM.LBS (10**4)	CTD.LBS (10**4)	MCFPD	CUM.MCF	CTD.MCF	BTU/DAY (10**6)	CUM.BTU (10**8)	CTD.BTU (10**8)
436.5	5979.7	5979.74	9.2	1258.2	1258.23	0.0	0.0	90.62

/----TOTAL FACILITY FUEL FLOW----/

MCF/DAY	CUM.MCF	CTD.MCF
659.8	1258.2	90392.68

WATER DISPOSAL

	BPD	BBL CUM(10**2)	BBL CTD(10**4)
TOTAL H2O DISPOSED	257.0	424.0	4.24
BACKWASH(SOFTENERS)	20.7	34.1	0.34
STEAM SEP.(TOT.-B/W)	236.3	389.9	3.9

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FROM 09/18/79 TO 02/29/80

OPERATING PRESSURES(PSIG)

INJECTION WELL NO.	DAILY AVG.	PERIOD AVG.	MINIMUM	MAXIMUM	AVERAGE TO-DATE
1/BX-31	1262.1	1258.3	6.00	1458.00	643.0
2/BX-16	1220.1	1212.1	3.67	1428.50	610.4
3/BX-30	1119.9	1049.5	1.00	1453.67	565.4
4/BX-17	1279.8	1281.5	3.00	1496.17	652.5
5/BX-32	1222.6	1208.4	7.17	1453.33	610.8
6/BX-24	1186.1	1171.9	1.00	1454.00	594.5
7/BX-23	1261.9	1244.8	1.00	1457.17	629.2
8/BX-33	1021.4	1010.9	4.67	1447.00	507.3
MONITOR WELL NO.					
1/BX-29	67.6	93.7	0.00	109.90	93.7
2/BX-34	1088.8	0.0	0.00	0.00	93.7
3/BX-35	9.0	0.0	0.00	0.00	93.7
SUPERHTR DISCHG.	326.0	812.2	0.00	1404.83	141.8

OPERATING TEMPERATURES (DEG.F)

	DAILY AVG.	PERIOD AVG.	MINIMUM	MAXIMUM	AVERAGE TO-DATE
SUPERHTR DIS.	453.8	455.8	0.00	885.10	80.0
STM.GEN.1 STK.	369.0	359.5	17.17	785.15	63.9
STM.GEN.2 STK.	390.1	396.4	11.62	762.78	70.5
SUPERHTR.STK.	209.4	208.5	13.18	789.20	37.1
INJ.WELL 1/BX-31	433.9	432.9	47.30	768.80	77.0
INJ.WELL 2/BX-16	504.3	421.4	29.60	1235.75	74.9
INJ.WELL 3/BX-30	341.4	336.6	14.75	663.27	59.8
INJ.WELL 4/BX-17	459.0	462.6	41.90	755.90	82.2
INJ.WELL 5/BX-32	483.7	479.8	31.47	745.70	85.3
INJ.WELL 6/BX-24	401.8	406.2	41.30	767.70	72.2
INJ.WELL 7/BX-23	529.4	527.7	67.83	871.78	93.8
INJ.WELL 8/BX-33	511.6	511.5	66.73	889.92	90.9
PROD.WELL 0/BX-19	49.6	49.2	14.27	76.80	8.7
PROD.WELL 1/BX-26	52.0	51.0	0.70	73.50	9.1
PROD.WELL 2/BX-20	43.4	43.6	11.30	74.85	7.8
PROD.WELL 3/BX-14	75.4	73.7	5.50	101.35	13.1
PROD.WELL 4/BX-21	52.0	51.6	6.10	78.07	9.2

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TEMPERATURE OBSERVATION WELLS

	/-DAILY AVG. TEMPERATURE-/			/-PERIOD AVG.TEMPERATURE-/			/--MINIMUM TEMPERATURE---/			/--MAXIMUM TEMPERATURE---/		
DEPTH	NO.1	NO.2	NO.3	NO.1	NO.2	NO.3	NO.1	NO.2	NO.3	NO.1	NO.2	NO.3
450.0	55.3	86.0	75.1	55.3	85.6	75.0	52.05	75.30	71.87	57.87	182.53	85.82
500.0	55.8	84.1	76.3	55.8	83.8	76.3	52.75	65.40	73.20	58.33	139.48	84.72
600.0	59.6	86.2	83.0	59.6	85.8	82.6	56.50	75.25	69.30	61.68	139.52	111.15
700.0	65.4	86.0	103.3	65.3	85.7	102.6	62.54	76.10	77.88	68.87	157.87	165.85
760.0	64.6	98.8	87.0	64.6	97.4	86.7	61.45	77.20	72.70	66.77	245.07	114.80
780.0	64.0	85.7	93.2	64.0	85.6	92.8	61.10	66.92	77.81	66.28	124.83	124.38
-----S-T-A-R-T---U-P-P-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E-----												
800.0	65.8	100.3	77.6	65.7	99.1	77.6	62.30	69.45	66.40	72.53	266.70	84.50
820.0	75.8	106.3	78.4	75.3	106.2	78.4	68.65	103.80	66.55	104.62	107.73	89.53
840.0	85.1	97.0	78.0	84.0	96.9	77.9	72.72	94.50	66.00	148.85	101.35	84.40
860.0	119.7	99.2	79.7	117.1	99.2	79.7	73.27	96.08	67.85	278.12	100.62	83.30
-----E-N-D---U-P-P-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E-----												
880.0	174.5	99.1	81.4	169.7	99.0	81.4	73.80	96.32	71.05	468.50	105.92	85.70
900.0	77.9	96.7	84.8	77.4	96.7	84.9	69.74	93.65	73.45	110.08	100.30	89.65
920.0	71.3	106.1	85.2	72.0	106.2	85.2	31.13	98.36	72.70	79.40	110.10	88.63
940.0	70.8	102.9	91.1	70.4	102.9	91.1	55.97	95.64	79.40	94.98	107.48	95.00
960.0	82.1	103.0	94.6	81.8	102.8	94.6	70.70	90.83	82.35	117.00	118.33	97.90
-----S-T-A-R-T---P-R-O-D-U-C-T-I-O-N---Z-O-N-E-----												
980.0	82.0	149.1	95.5	81.7	149.1	95.4	71.50	109.86	83.70	111.26	184.55	102.62
1000.0	78.3	190.0	104.6	78.2	190.1	104.6	70.03	127.46	92.60	119.50	221.38	110.07
1020.0	84.6	171.9		82.3	171.8		57.73	137.38		236.67	199.38	
1040.0	84.1	120.3	85.2	83.5	120.2	85.8	73.87	102.74	41.72	135.00	135.68	98.77
1060.0	84.8	94.2	98.9	84.7	94.3	99.1	75.77	90.82	75.90	99.88	97.10	140.80
1080.0	85.1	56.8	109.9	85.0	56.8	110.7	76.77	55.80	56.23	99.00	58.20	242.72
1100.0	84.4	57.9	133.4	84.3	57.9	133.1	76.00	56.60	113.20	101.98	59.90	168.27
1120.0	87.1	58.8	154.7	86.9	58.8	156.0	77.40	56.60	88.25	108.18	60.40	186.25
1140.0	87.3	61.5	88.5	87.4	61.5	89.0	69.56	59.20	53.93	101.38	63.20	111.10
-----E-N-D---P-R-O-D-U-C-T-I-O-N---Z-O-N-E-----												
1160.0	90.7	63.7	86.5	90.8	63.7	86.3	78.18	62.10	78.60	94.53	64.70	121.60
1180.0	85.0	65.7	57.6	85.7	65.7	57.6	39.35	63.90	51.85	116.66	67.25	60.67
1200.0	90.6	68.1	61.2	90.2	68.1	61.1	79.42	66.40	55.30	170.34	74.34	64.73
1220.0	77.9	78.1	63.8	77.9	77.3	63.8	70.98	67.10	58.10	101.08	127.20	65.95
1240.0	80.4	89.8	65.8	80.1	88.4	65.8	71.30	69.54	60.05	121.37	175.12	67.77
-----S-T-A-R-T---L-O-W-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E-----												
1260.0	80.0	140.9	68.1	79.8	136.5	68.1	71.65	71.23	62.30	121.05	444.20	70.07
1280.0	84.9	140.7	70.0	84.2	135.5	69.9	71.05	72.74	39.10	146.42	416.68	72.67
1300.0	83.8	78.4	73.5	83.3	77.8	73.4	73.40	70.90	67.00	143.00	145.85	82.02
1320.0	81.2	76.7	98.2	81.0	76.5	97.3	72.00	66.97	50.35	119.40	87.73	328.73
1340.0	79.4	73.3	97.8	79.2	73.3	96.5	67.35	64.37	83.70	106.68	75.75	304.07
1360.0	82.2	73.7		82.2	73.6		75.75	70.98		97.37	86.80	
-----E-N-D---L-O-W-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E-----												

***** KEY TO OBSERVATION WELLS *****

OBS. WELL NO. 1=BX-29
OBS. WELL NO. 2=BX-34
OBS. WELL NO. 3=BX-35

A	5620000	517	1224.16	0	453.82	326.03+00000014.16
A	5620000	518	1224.16	0	453.82	326.03+00000024.50
A	5620000	519	1224.16	0	453.82	326.03+00000000.00
A	5620000	520	1224.16	0	453.82	326.03+00000000.00
A	5620000	521	1224.16	0	453.82	326.03+00000040.38
A	5620000	522	1224.16	0	453.82	326.03+00000120.61

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Appendix "G"

REPORT PERIOD

FROM TO

DETAIL SUMMARY OF DAYS INCLUDED IN THIS REPORT

DATA COLLECTED FOR DECEMBER 1, 1979
DATA COLLECTED FOR DECEMBER 2, 1979
DATA COLLECTED FOR DECEMBER 3, 1979
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DATA COLLECTED FOR FEBRUARY 2, 1980
DATA COLLECTED FOR FEBRUARY 3, 1980

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DATA COLLECTED FOR FEBRUARY 4, 1980
DATA COLLECTED FOR FEBRUARY 5, 1980
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DATA COLLECTED FOR FEBRUARY 24, 1980
DATA COLLECTED FOR FEBRUARY 25, 1980

*** TABLE OF ENTHALPIES ****

1	1178.78
2	1179.21
3	1183.84
4	1178.14
5	1183.27
6	1179.01
7	1178.76
8	1191.59
9	1231.93

EQUITY OIL CO./U.S. DEPARTMENT OF ENERGY

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FROM 12/01/79 TO 02/29/80

INJECTION

WELL	BBLS/DAY	CUM.BBLS 10**2	BTU/DAY 10**6	CUM.BTU 10**8	CTD.BBLS 10**2	CTD.BTU 10**8
1/BX-31	177.44	115.3	73.2	47.6	115.33	115.33
2/BX-16	154.58	106.7	63.8	44.0	106.66	106.66
3/BX-30	45.84	31.6	19.0	13.1	31.63	31.63
4/BX-17	147.53	101.8	60.8	42.0	101.79	101.79
5/BX-32	259.13	178.8	107.3	74.1	178.80	178.80
6/BX-24	109.53	75.6	45.2	31.2	75.58	75.58
7/BX-23	131.87	89.7	54.4	37.0	89.67	89.67
8/BX-33	289.89	200.0	120.9	83.4	200.03	200.03
TOTAL	1315.81	899.5	544.7	372.3	899.5	372.3

INJECTION DOWNTIME

WELL NO.	1	2	3	4	5	6	7	8
DAYS BELOW SET LIMIT	26	22	22	22	22	22	23	22
SET LIMIT IN BBLS/DAY	0.686	0.686	0.686	0.686	0.686	0.686	0.686	0.686
CUMULATIVE DOWNTIME TO-DATE	100	96	96	96	96	96	97	96
TOTAL INJECTION DAYS TO-DATE	65	69	69	69	69	69	68	69

PRODUCTION

	WATER			OIL		
	BBL/DAY	BBL CUM(10**2)	BBL CTD(10**3)	BBL/DAY	BBL CUM(10**2)	BBL CTD(10**2)
TEST SEP	159.1	144.8	14.48	0.0	0.0	0.00
FWKO	923.7	840.5	84.05	0.0	0.0	0.00
TOTAL	1082.8	985.3	98.5	0.0	0.0	0.0

	GAS		
	MCF/DAY	MCF CUM(10**2)	MCF CTD(10**3)
TEST SEP	71.7	65.2	6.52
FWKO	264.4	240.6	24.06
TOTAL	336.1	305.8	30.6
INPUT	401.5	365.4	36.54
NET	-65.5	-59.6	-6.0

***** KEY FOR GAS PRODUCED *****
NET(+)=FORMATION GAS PRODUCED
NET(-)=GAS LIFT + GAS LOST

FLUID PRODUCTION
PRODUCTION SURVEILLANCE MONITOR

WELL NO.	BBL/DAY	CUM.BBL (10**2)	CTD.BBL (10**2)
0/BX-19	285.1	259.4	259.41
1/BX-26	317.7	289.1	289.09
2/BX-20	182.9	166.4	166.44
3/BX-14	294.6	268.1	268.10
4/BX-21	277.0	252.0	252.03

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BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

REPORT PERIOD

FROM 12/01/79 TO 02/29/80

STEAM GENERATION

	FEED-WATER BPD 10**2	FEED-WATER BBL CUM 10**2	FEED-WATER BBL CTD 10**3	FUEL MCFPD	FUEL CUM.MCF	FUEL CTD.MCF	FUEL BTU/DAY (10**6)	FUEL CUM.BTU (10**8)	FUEL CTD.BTU (10**8)
STEAM GEN.1	10.1	687.4	68.74	130.8	8892.5	36.54	130.8	88.9	88.93
STEAM GEN.2	14.2	963.8	96.38	292.3	19879.4	8892.52	292.3	198.8	198.79
TOTAL	24.3	1651.2	165.1	423.1	28771.9	28771.9	423.1	287.7	287.7

SUPERHEATER

TOTAL-STEAM LBS/DAY (10**3)	TOTAL-STEAM CUM.LBS (10**4)	TOTAL-STEAM CTD.LBS (10**4)	FUEL MCFPD	FUEL CUM.MCF	FUEL CTD.MCF	FUEL BTU/DAY (10**6)	FUEL CUM.BTU (10**8)	FUEL CTD.BTU (10**8)
413.4	2812.4	2812.37	5.7	390.7	390.71	0.0	0.0	47.58

/----TOTAL FACILITY FUEL FLOW----/

MCF/DAY	CUM.MCF	CTD.MCF
616.4	390.7	41912.59

WATER DISPOSAL

	BPD	BBL CUM(10**2)	BBL CTD(10**4)
TOTAL H2O DISPOSED	221.8	201.8	2.02
BACKWASH(SOFTENERS)	23.2	21.2	0.21
STEAM SEP.(TOT.-B/W)	198.5	180.6	1.8

EQUITY OIL CO./U.S. DEPARTMENT OF ENERGY

BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

REPORT PERIOD

FROM 12/01/79 TO 02/29/80

OPERATING PRESSURES(PSIG)

INJECTION WELL NO.	DAILY AVG.	PERIOD AVG.	MINIMUM	MAXIMUM	AVERAGE TO-DATE
1/BX-31	1329.9	1333.8	842.80	1458.00	691.6
2/BX-16	1321.0	1323.6	834.60	1428.50	666.5
3/BX-30	1221.8	1167.7	1.00	1453.67	588.1
4/BX-17	1343.0	1354.7	861.80	1496.17	682.2
5/BX-32	1234.5	1218.2	567.60	1453.33	613.5
6/BX-24	1325.3	1326.9	838.00	1454.00	668.2
7/BX-23	1330.5	1334.4	838.80	1457.17	676.8
8/BX-33	1035.9	1031.8	4.67	1447.00	519.6
MONITOR WELL NO.					
1/BX-29	3.7	3.7	0.00	4.47	3.7
2/BX-34	0.0	0.0	0.00	0.00	3.7
3/BX-35	9.0	0.0	0.00	0.00	3.7
SUPERHTR DISCHG.	69.5	57.0	0.00	566.00	3.6

OPERATING TEMPERATURES (DEG.F)

	DAILY AVG.	PERIOD AVG.	MINIMUM	MAXIMUM	AVERAGE TO-DATE
SUPERHTR DIS.	399.8	403.1	377.00	748.22	37.0
STM.GEN.1 STK.	251.6	232.0	17.17	532.22	21.3
STM.GEN.2 STK.	402.6	415.8	49.00	511.87	38.2
SUPERHTR.STK.	115.4	120.6	13.18	645.78	11.1
INJ.WELL 1/BX-31	429.6	430.6	284.60	557.90	39.6
INJ.WELL 2/BX-16	478.2	447.9	0.00	1235.75	40.6
INJ.WELL 3/BX-30	360.3	356.3	34.70	498.58	32.8
INJ.WELL 4/BX-17	475.7	485.7	270.54	606.45	44.6
INJ.WELL 5/BX-32	455.0	451.8	31.47	630.85	41.5
INJ.WELL 6/BX-24	408.0	414.2	268.02	609.45	38.1
INJ.WELL 7/BX-23	558.1	557.1	374.90	738.27	51.2
INJ.WELL 8/BX-33	498.5	501.3	66.78	744.22	46.1
PROD.WELL 0/BX-19	43.7	43.7	14.49	64.72	4.0
PROD.WELL 1/BX-26	42.0	41.1	0.70	61.80	3.8
PROD.WELL 2/BX-20	29.9	30.8	11.82	74.85	2.8
PROD.WELL 3/BX-14	84.6	82.4	13.10	101.35	7.6
PROD.WELL 4/BX-21	48.5	48.5	11.57	78.07	4.5

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BX IN SITU OIL SHALE PROJECT
OPERATIONS REPORT
PROJECT MGR.: PAUL M. DOUGAN

REPORT PERIOD

FROM 12/01/79 TO 02/29/80

TEMPERATURE OBSERVATION WELLS

	/-DAILY AVG. TEMPERATURE-/			/-PERIOD AVG.TEMPERATURE-/			/--MINIMUM TEMPERATURE---/			/--MAXIMUM TEMPERATURE---/		
DEPTH	NO.1	NO.2	NO.3	NO.1	NO.2	NO.3	NO.1	NO.2	NO.3	NO.1	NO.2	NO.3
450.0	56.3	89.5	75.5	56.2	88.6	75.3	52.05	75.30	71.87	57.87	182.53	85.82
500.0	56.8	85.9	77.8	56.7	85.3	77.8	52.75	65.40	73.20	58.33	139.48	84.72
600.0	60.4	90.9	92.0	60.3	89.9	91.1	56.50	75.25	69.30	61.68	139.52	111.15
700.0	66.7	90.9	123.8	66.6	90.1	122.0	62.85	76.10	86.73	68.87	157.87	165.85
760.0	65.0	115.7	95.6	65.0	112.7	94.6	61.45	77.20	72.70	66.77	245.07	114.80
780.0	64.3	89.5	104.4	64.2	89.1	103.3	61.10	66.92	77.95	66.28	124.83	124.38
S-T-A-R-T---U-P-P-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E												
800.0	67.3	110.8	80.0	67.1	108.3	79.8	62.30	69.45	66.40	72.53	266.70	84.50
820.0	81.4	106.5	80.9	80.5	106.4	80.6	69.20	105.50	66.55	104.62	107.73	89.53
840.0	96.0	97.8	79.9	93.8	97.7	79.6	73.45	95.70	66.00	148.85	101.35	84.40
860.0	163.7	99.6	80.9	158.4	99.6	80.7	76.92	98.90	67.85	278.12	100.62	83.30
E-N-D---U-P-P-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E												
880.0	268.0	100.3	82.9	258.6	100.2	82.8	95.32	98.28	71.05	468.50	105.92	85.70
900.0	85.3	98.3	86.2	83.9	98.2	86.1	70.70	96.33	73.45	110.08	100.30	89.65
920.0	68.8	106.7	86.2	70.0	106.8	85.9	31.13	103.53	72.70	79.40	109.37	88.63
940.0	69.8	104.0	92.5	68.9	103.9	92.3	55.97	101.23	79.40	94.98	107.48	95.00
960.0	87.8	108.7	95.1	87.0	108.3	94.9	76.77	101.90	82.35	117.00	118.33	97.70
S-T-A-R-T---P-R-O-D-U-C-T-I-O-N---Z-O-N-E												
980.0	87.5	165.1	97.3	86.8	164.5	97.0	77.03	142.93	83.70	111.26	184.55	102.62
1000.0	83.0	212.7	106.6	82.7	212.4	106.5	70.65	193.84	92.60	119.50	221.38	110.07
1020.0	97.8	188.6		93.1	188.1		57.73	169.93		236.67	199.38	
1040.0	89.0	128.2	84.1	87.7	128.0	85.3	77.20	116.57	41.72	135.00	135.68	98.77
1060.0	88.0	94.3	106.0	87.7	94.4	106.2	81.57	93.00	75.90	99.88	97.10	140.80
1080.0	88.0	56.6	112.8	87.7	56.6	114.3	83.10	55.80	56.23	99.00	58.20	242.72
1100.0	87.6	57.5	146.7	87.4	57.5	145.7	81.70	56.63	125.58	101.98	59.90	168.27
1120.0	91.1	59.2	156.1	90.5	59.2	158.5	82.98	56.60	88.25	108.18	59.86	186.25
1140.0	85.3	61.7	87.8	85.6	61.7	88.6	69.56	59.20	53.93	99.28	62.27	111.10
E-N-D---P-R-O-D-U-C-T-I-O-N---Z-O-N-E												
1160.0	91.3	63.9	87.5	91.4	63.9	87.1	78.18	62.10	78.60	94.53	64.33	121.60
1180.0	84.8	66.1	58.6	86.0	66.0	58.4	39.35	63.90	51.85	116.66	67.25	60.67
1200.0	95.7	69.3	62.4	94.8	69.1	62.2	84.35	66.40	55.30	170.34	74.34	64.73
1220.0	81.1	88.2	64.6	81.0	86.4	64.5	70.98	68.68	58.10	101.08	127.20	65.95
1240.0	86.1	108.4	66.4	85.4	105.3	66.3	71.30	72.60	60.05	121.37	175.12	67.77
S-T-A-R-T---L-O-W-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E												
1260.0	82.3	209.2	68.7	81.8	199.5	68.6	71.65	71.23	62.30	121.05	444.20	70.07
1280.0	94.1	207.2	70.7	92.6	195.9	70.3	71.05	74.70	39.10	146.42	416.68	72.67
1300.0	91.7	85.4	75.6	90.5	84.1	75.3	73.40	71.55	67.00	143.00	145.85	82.02
1320.0	84.6	75.2	105.9	84.2	74.7	104.0	72.00	66.97	50.35	119.40	87.73	328.73
1340.0	82.7	72.3	108.0	82.3	72.3	105.1	67.35	64.37	83.70	106.68	75.75	304.07
1360.0	85.1	73.6		85.0	73.5		75.75	70.98		97.37	86.80	
E-N-D---L-O-W-E-R---I-N-J-E-C-T-I-O-N---Z-O-N-E												

***** KEY TO OBSERVATION WELLS *****
OBS. WELL NO. 1=BX-29
OBS. WELL NO. 2=BX-34
OBS. WELL NO. 3=BX-35

APPENDIX "H"

QUARTERLY AIR RESOURCES REPORT

September - November, 1979

EQUITY OIL COMPANY
BX In-Situ Oil Shale Project
Piceance Basin, Colorado

Prepared by
VTN CONSOLIDATED, Inc.

January, 1980

1.0 INTRODUCTION

This report provides a summary of the meteorological data collected from the mechanical weather station located at the ridge site along Black Sulphur Gulch during the months of September, October and November, 1979. Data recovery during the period was 100% for the temperature and 97.9% for the wind speed parameters.

2.0 SITE METEOROLOGY

2.1 Wind

Winds during the period from September-November 1979 period continue to show an overwhelming influence of local topography on the flow patterns. The two dominating wind directions accounting for almost 47% of all the data, were southwest and south-southwest. A secondary maximum occurred from the northeast direction, accounting for an additional 17.6% of the data. Examination of the data shows that occurrences of northeast winds coincides with periods of intense solar heating in the valley, causing frequent but weak upslope winds, i.e., from the northeast during the day.

Monthly summaries of the wind speed and direction data for September, October and November 1979 are given in Tables 1, 2 and 3, respectively. The summarized data for the three-month period are given in Table 4 by their occurrences and in Table 5 by the frequency distribution. A wind rose for the period is shown in Figure 1.

The wind speed data summarized in Table 6 shows that winds were below 3 miles per hour for 41.3% of the time. The wind speed exceeds 12 mph 11.1% of the time and only 3% of the winds were above 18 mph.

2.2 Temperature

A summary of the temperature data is presented in Table 7 with data for the individual months being given in Tables 8, 9 and 10. The maximum temperature was 89°F (31.7°C), which was recorded on September 6, 1979.

The minimum temperature reached was -12°F (-24.4°C) on November 29, 1979. The average daily temperature was 41.6°F (5.3°C) for the three-month period. The temperature fell below freezing on 51 occasions starting in September.

TABLE 1

WIND OBSERVATIONS: EQUITY OIL RIDGE SITE

September 1979

Direction	Speed (mph) 0-3	4-7	8-12	13-18	19-24	>24	Total	Average Speed
N	7	12	11	1	0	0	31	6.2
NNE	11	17	11	5	0	0	44	6.3
NE	41	47	18	3	0	0	109	4.4
NE	24	6	0	0	0	0	30	2.2
E	6	2	0	0	0	0	8	2.1
ESE	2	0	0	0	0	0	2	1.2
SE	1	0	0	0	0	0	1	2.5
SSE	3	0	0	0	0	0	3	1.8
S	5	4	0	0	0	0	9	2.8
SSW	33	40	31	16	2	0	122	6.6
SW	65	68	62	37	3	0	235	6.8
WSW	22	13	16	4	0	0	55	5.6
W	7	8	23	3	0	0	41	7.2
WNW	6	3	5	0	0	0	14	4.8
NW	3	2	3	0	0	0	8	5.0
NNW	1	4	2	0	0	0	7	6.0
TOTAL	237	226	182	69	5	0		

Total Observations = 719
Total Calm Winds = 36
Average Wind Speed = 5.9 mph

TABLE 2

WIND OBSERVATIONS: EQUITY OIL RIDGE SITE

October 1979

	Speed (mph)							
Direction	0-3	4-7	8-12	13-18	19-24	>24	Total	Average Speed
N	0	7	12	4	0	0	23	8.4
NNE	4	4	5	3	0	0	16	7.2
NE	65	68	2	0	0	4	139	6.0
ENE	24	5	0	0	0	0	29	1.9
E	12	1	0	0	0	1	14	8.8
ESE	4	1	0	0	0	0	5	1.7
SE	1	1	0	0	0	0	2	2.4
SSE	3	2	0	0	0	0	5	2.2
S	13	7	2	0	0	0	22	3.2
SSW	70	31	24	17	3	10	155	11.0
SW	109	45	19	8	1	8	190	6.2
WSW	25	22	13	6	1	1	68	6.8
W	5	5	6	0	0	0	16	5.5
WNW	1	3	0	0	0	0	4	4.7
NW	3	2	0	0	0	0	5	2.8
NNW	1	4	0	0	0	0	5	4.0
TOTAL	340	208	83	38	5	24		

Total Observations = 698
Total Calm Winds = 85
Average Wind Speed = 7.0 mph

TABLE 3

WIND OBSERVATIONS: EQUITY OIL RIDGE SITE

November 1979

Direction	Speed (mph) 0-3	4-7	8-12	13-18	19-24	>24	Total	Average Speed
N	5	9	17	12	0	1	44	11.3
NNE	12	13	8	9	4	0	46	8.5
NE	36	74	18	0	1	0	129	4.7
ENE	24	6	0	0	0	0	30	2.0
E	4	0	0	0	0	0	4	1.6
ESE	1	0	0	0	0	0	1	1.0
SE	6	0	0	0	0	0	6	1.7
SSE	1	0	0	0	0	0	1	1.7
S	17	7	1	1	0	0	26	3.1
SSW	57	16	18	4	1	2	98	5.0
SW	94	35	34	30	12	10	215	7.7
WSW	30	14	13	4	0	0	61	4.9
W	12	5	11	4	0	0	32	6.4
WNW	3	1	6	1	0	0	11	7.3
NW	2	8	2	0	0	0	12	5.3
NNW	3	2	0	0	0	0	5	2.6
TOTAL	307	190	128	65	13	18		

Total Observations = 721
Total Calm Winds = 59
Average Wind Speed = 6.2 mph

TABLE 4

WIND OBSERVATIONS: EQUITY OIL RIDGE SITE

September - November 1979

Direction	Speed (mph) 0-3	4-7	8-12	13-18	19-24	>24	Total	Average Speed
N	12	28	40	17	0	1	98	9.0
NNE	27	34	24	17	4	0	106	7.4
NE	142	189	38	3	1	4	377	5.7
ENE	72	16	0	0	0	1	89	2.0
E	22	3	0	0	0	0	25	5.9
ESE	7	1	0	0	0	0	8	1.5
SE	8	1	U	0	0	0	9	1.9
SSE	7	2	0	0	0	0	9	2.0
S	35	18	3	1	0	10	67	2.6
SSW	160	87	73	37	6	10	373	7.5
SW	268	148	115	75	16	11	633	6.1
WSW	77	49	42	14	1	0	183	5.8
W	24	18	40	7	0	0	89	6.6
WNW	10	7	11	1	0	0	29	5.7
NW	8	12	5	0	0	0	25	4.7
NNW	5	10	2	0	0	0	17	4 4
TOTAL	884	624	393	172	28	37		

Total Observations = 2138
Total Calm Winds = 180
Average Wind Speed = 6.4 mph

TABLE 5

WIND FREQUENCY DISTRIBUTION: EQUITY OIL RIDGE SITE

September - November 1979

	Speed (mph)						
Direction	0-3	4-7	8-12	13-18	19-24	>24	Total
N	0.0056	0.0131	0.0187	0.0080	0.0000	0.0005	0.0459
NNE	0.0126	0.0159	0.0112	0.0080	0.0019	0.0000	0.0496
NE	0.0664	0.0884	0.0178	0.0014	0.0005	0.0019	0.1764
ENE	0.0337	0.0075	0.0000	0.0000	0.0000	0.0005	0.0417
E	0.0103	0.0014	0.0000	0.0000	0.0000	0.0000	0.0117
ESE	0.0033	0.0005	0.0000	0.0000	0.0000	0.0000	0.0038
SE	0.0037	0.0005	0.0000	0.0000	0.0000	0.0000	0.0042
SSE	0.0033	0.0009	0.0000	0.0000	0.0000	0.0000	0.0042
S	0.0164	0.0084	0.0014	0.0005	0.0000	0.0047	0.0314
SSW	0.0748	0.0407	0.0341	0.0173	0.0028	0.0047	0.1744
SW	0.1254	0.0692	0.0538	0.0351	0.0075	0.0051	0.2961
WSW	0.0360	0.0229	0.0196	0.0065	0.0005	0.0000	0.0855
W	0.0112	0.0084	0.0187	0.0033	0.0000	0.0000	0.0416
WNW	0.0047	0.0033	0.0051	0.0005	0.0000	0.0000	0.0136
NW	0.0037	0.0056	0.0033	0.0000	0.0000	0.0000	0.0116
NNW	0.0023	0.0047	0.0009	0.0000	0.0000	0.0000	0.0079
TOTAL	0.4134	0.2914	0.1836	0.0806	0.0132	0.0174	0.9996

Frequency of all Calm Winds = 0.0842
Total Observations = 2,138
Average Wind Speed = 6.4 mph

TABLE 6

WIND FREQUENCY DISTRIBUTION: EQUITY OIL RIDGE SITE

September - November 1979

Month	Speed (mph) 0-3	4-7	8-12	13-18	19-24	>24	Total
September	0.3296	0.3143	0.2531	0.0959	0.0069	0.0000	0.9999
October	0.4257	0.2635	0.1775	0.0901	0.0249	0.0180	0.9999
November	0.4871	0.2979	0.1189	0.0544	0.0071	0.0343	0.9999
Season	0.4134	0.2914	0.1836	0.0806	0.0132	0.0174	0.9996

TABLE 7

MONTHLY TEMPERATURE DATA
(Degrees F)

EQUITY OIL RIDGE SITE: September - November 1979

Month	Mean Monthly	Average Maximum	Average Minimum	Maximum	Minimum
September	60.9	77.4	42.5	89	25
October	44.8	60.0	32.2	80	-1
November	20.6	33.6	10.2	51	-12
Season	41.6	57.0	28.3	89	-12

TABLE 8

TEMPERATURE DATA: EQUITY OIL RIDGE SITE
(Degrees F)

September 1979

Maximum Temperature	--	89
Minimum Temperature	--	25
Average Maximum	--	77.4
Average Minimum	--	42.5
Mean Monthly Temperature	--	60.9

Date	Maximum	Minimum	Mean	Range
1	81	42	65	39
2	80	51	67	29
3	83	51	68	32
4	82	60	72	22
5	88	49	69	39
6	89	49	68	40
7	88	51	69	37
8	86	55	70	31
9	87	55	71	32
10	79	25	62	54
11	80	47	64	33
12	69	31	53	38
13	62	34	49	28
14	61	29	47	32
15	72	29	53	43
16	79	32	58	47
17	78	39	58	39
18	83	41	62	42
19	78	48	61	30
20	73	45	60	28
21	72	39	57	33
22	77	43	62	34
23	78	43	64	35
24	81	47	62	34
25	76	48	61	28
26	69	48	57	21
27	70	36	51	34
28	71	35	54	36
29	75	38	55	37
30	75	38	57	37

TABLE 9

TEMPERATURE DATA: EQUITY OIL RIDGE SITE
(Degrees F)

October 1979

Maximum Temperature	--	80
Minimum Temperature	--	-1
Average Maximum	--	60
Average Minimum	--	32.2
Mean Monthly Temperature	--	44.8

Date	Maximum	Minimum	Mean	Range
1	76	39	57	37
2	76	43	60	33
3	60	38	48	22
4	73	30	50	43
5	72	36	54	36
6	78	38	56	40
7	80	40	60	40
8	76	46	60	30
9	61	24	43	37
10	72	30	51	42
11	75	39	55	36
12	69	38	53	31
13	73	35	54	38
14	69	45	52	24
15	64	35	51	29
16	52	33	43	19
17	63	24	44	39
18	60	31	48	29
19	60	51	55	9
20	54	28	32	26
21	30	24	28	6
22	44	23	30	21
23	58	24	38	34
24	59	24	38	35
25	63	30	47	33
26	61	40	50	21
27	50	23	37	17
28	53	21	37	32
29	32	25	28	7
30	25	10	21	15
31	24	-1	11	25

TABLE 10

TEMPERATURE DATA: EQUITY OIL RIDGE SITE
(Degrees F)

November 1979

Maximum Temperature	--	51
Minimum Temperature	--	12
Average Maximum	--	33.6
Average Minimum	--	10.2
Mean Monthly Temperature	--	20.6

Date	Maximum	Minimum	Mean	Range
1	31	-2	13	33
2	41	8	20	33
3	43	11	29	32
4	45	21	33	24
5	42	18	27	24
6	49	18	31	31
7	41	22	34	19
8	42	22	30	20
9	37	23	29	14
10	38	10	25	28
11	29	16	24	13
12	42	12	24	30
13	40	11	24	29
14	42	11	24	31
15	43	12	25	31
16	51	11	28	40
17	49	19	33	30
18	39	20	29	19
19	21	14	19	7
20	20	11	17	9
21	15	1	9	14
22	23	-1	8	24
23	28	2	13	26
24	27	9	17	18
25	28	19	22	9
26	34	12	24	22
27	25	-2	9	27
28	17	-10	1	27
29	12	-12	-2	24
30	14	-11	-1	25

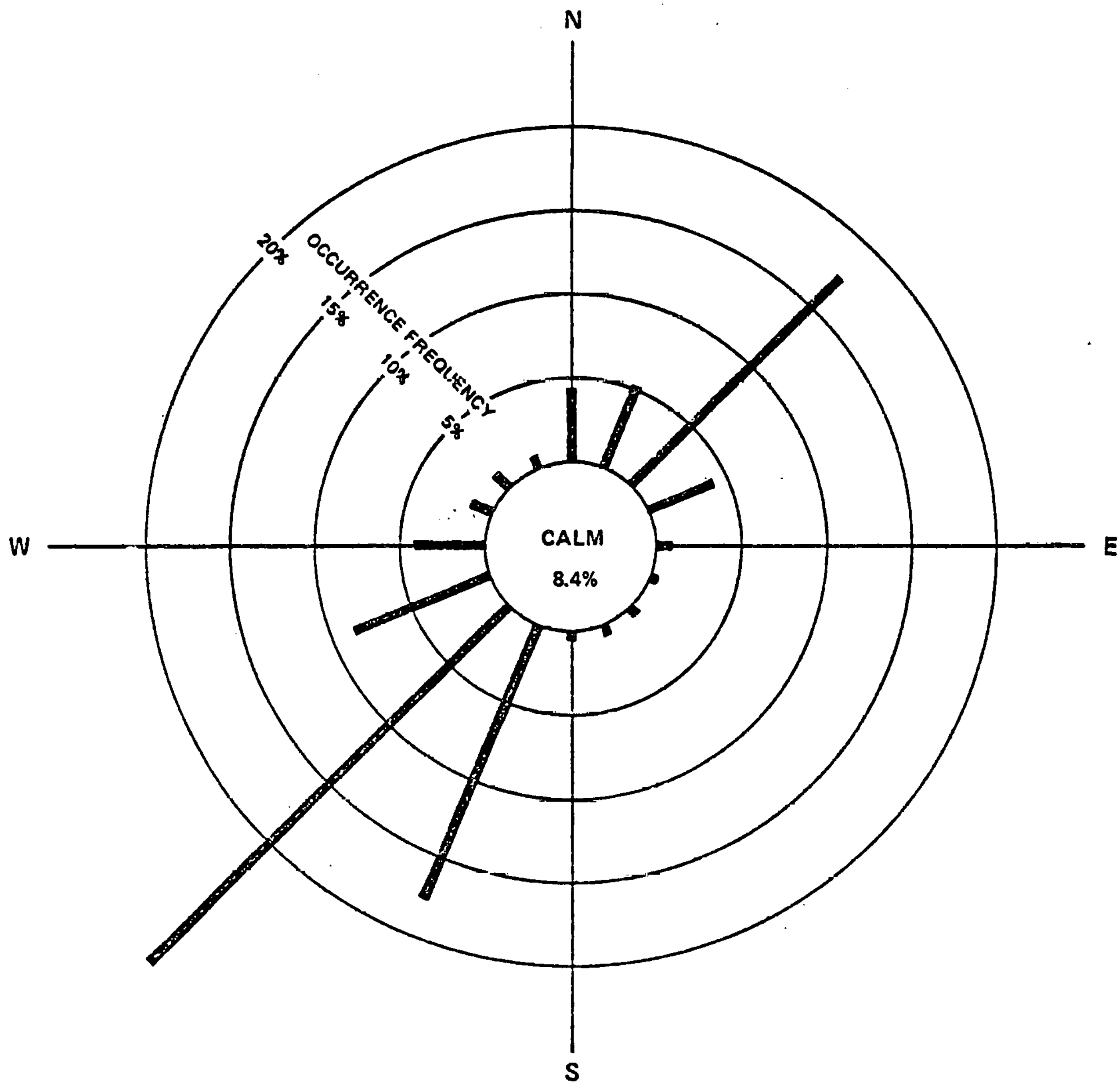

FIGURE 1

SEASONAL WIND DIRECTION
RELATIVE FREQUENCY DISTRIBUTION (%)
SEPTEMBER, OCTOBER, NOVEMBER, 1979

QUARTERLY REPORT

DECEMBER 1, 1979 - FEBRUARY 29, 1980

EQUITY OIL COMPANY
BX In-Situ Oil Shale Project
Piceance Basin, Colorado

Prepared by

VTN Consolidated, Inc.

March 17, 1980

SUMMARY

WORK PERFORMED

Air Resources

Meteorological data was collected continuously at the mechanical weather station and at the meteorological tower. A quarterly summary of mechanical station data was completed for the period September through November, 1979, and is attached for review.

Water Resources

Water quality samples and field readings were taken as shown on the following table.

Sufficient water is no longer available in BX-13 for sampling.

Aquatic Biology

A regularly scheduled field trip was conducted to collect benthic invertebrate and phytoplankton samples from Black Sulphur Creek. A summary of sample analysis results is attached for review.

WORK SCHEDULED

Air Resources

Data will be collected continuously at the mechanical weather station and the meteorological tower. The data will be reduced and summarized into quarterly reports.

Water Resources

ES-2, leached zone and upper aquifer water quality samples will be taken semi-monthly. ES-3 samples will be taken monthly. Semi-monthly field measurements will be taken at each of these sample points. Monthly field measurements will be taken at the alluvial wells.

Samples will also be taken of process water semi-monthly at the free water knockout to determine the chemical constituents most likely to occur at monitoring wells. Semi-monthly samples will be taken at the disposal tank to determine the quality of wastes injected into the leached zone.

Aquatic Biology

One trip is planned to Black Sulphur Creek to collect benthic invertebrate and periphyton samples.

Station		12/3/79	12/6/79	12/20/79	12/27/79	1/3/80	1/10/80	1/21/80	1/24/80	1/25/80	1/31/80	2/7/80	2/14/80	2/21/80
ES-2	Field	X			X		X	X	X			X		X
	Lab	X			X		X	X	X			X		X
ES-3	Field	X	X	X	X	X	X	X		X	X	X	X	X
	Lab	X	X	X	X	X	X	X		X	X	X	X	X
BX-13	Field	X	X	X	X	X								
	Lab	X	X	X	X									
BX-36	Field		X	X		X	X		X		X	X	X	X
	Lab		X	X		X	X		X		X	X	X	X
A-1, -1A, -2,-3,-4	Field	X			X				X					
	Lab													

EQUITY OIL COMPANY, BX INSITU OIL SHALE PROJECT, REPORT FOR JANUARY 15, 1980 FIELD VISIT

Benthic macroinvertebrates and periphyton algae were sampled at each of the weirs on Black Sulfur Creek, Rio Blanco County, Colorado. In addition, observations of the habitat conditions in the immediate area were made.

Habitat Observations

Stream conditions at the upper weir were similar to previous field visits in 1978 and 1979. The substrate consisted mostly of pebbles one to three inches in diameter with little sand or silt. The bank had sage brush and grasses growing down to the water. At the lower weir changes in stream conditions first noted during the August 1979 visit were observed again in January 1980. Most notable were substantial streambed and bank alterations. It appeared that the streambank was leveled and graded above the weir. Below the weir it appeared that the streambed had been dredged and the overburden piled along the south bank creating a berm one to two feet high and two to four feet wide. Shoreline vegetation was sparce and the banks were unstable below the weir. The original stream course did not appear to have been channelized, although the stream gradient may have been altered. The substrate at the lower weir consisted of small gravel (1/4-1/2 inch) mixed with sand and silt.

Periphyton Algae

There was a total of 44 diatom species found in the January 1980 samples. Each of the following diatom species represented more than 10% of the total density: *Achnanthes minutissima*, *Navicula viridula*, *N. secreta*, *Gomphonema olivaceum* and *Cymbella minuta*. Structurally, the diatom communities of each station were similar as evidenced by the similar diversity indices. Also the abundant species were, with one exception, found at both stations. (Table 1).

Mean diatom density was greater at the upper weir than at the lower, with densities of 6,990 cells/mm^2 and 2,110 cells/mm^2, respectively. However, due to the large variance at each station the difference in diversities is not statistically significant (P=.05).

The diatom community is quite different from what it was last year for the comparable month of February, (VTN Annual Report, 1979). In 1979 the common diatoms at the upper and lower weirs differed. The common diatoms of the upper weir were *Achnanthes lanceolata*, *Cocconeis placentula* and *Navicula viridula*. The common diatoms of the lower weir were *Rhiocosphenia curvata*, *Synedra rumpens*, *Cymbella minuta*, and *Navicula* cryptocephala. The only abundant species that are common to this years assemblages are Cymbella minuta, and Navicula viridula. Also, this year there were more diatom species observed. The green algae Cladophora sp. and Tetrospora cylindrica were also present in the stream but were not collected as part of the sampling program.

The abundant diatoms from this field visit are usually found in hard waters. N. viridula prefers slightly alkaline water, and N. secreta is found in waters with a high mineral content. A. minutissima is quite pH tolerant occuring in waters between 6.5 and 9.0. G. olivaceum is usually found in hard waters with a high calcium concentration. Cladophora sp. is also found in high calcium environments (Patrick and Reimer, 1966; 1975). This reflects the water quality characteristics of Black Sulfur Creek.

Benthic Macroinvertebrates

There were several differences between the macroinvertebrate fauna of the lower and upper weirs in January 1980 (Table 2). The dominant taxa at the lower weir was Baetis tricaudatus, equaling 88.8% of the total fauna. At the upper weir chironomids dominated comprising 49.8% of the fauna, while Baetis tricaudatus comprised only 15.8%. Plecoptera and Trichoptera were sparse at the lower weir but common or abundant at the upper weir.

The total density of invertebrates was 898/m^2 at the lower weir and 9,174/m^2 at the upper weir. This is a statistically significant difference ($P=0.05$). The number of taxa and species diversity were also lower at the lower weir than at the upper weir (Table 2).

The results from this field trip contrasts with results from last years field trips. In February 1979, the lower weir was dominated by chironomids; Baetis spp. equaled less than 1.0% of the fauna. Chironomids were less abundant at the upper weir in 1979 than in 1980. Other taxa were similar at the upper weir between the two sample dates. In February 1979, density at the lower weir was over twice the density at the upper weir. Species diversities were higher at both stations in 1979 (VTN Annual Report, 1979). In August 1979, when stream alterations at the lower weir were first observed, the lower weir still showed a greater density of invertebrates than the upper weir. The difference was not statistically significant, however. Species diversities in August 1979, were similar to the February 1979, samples and higher than the January 1980 samples.

Summary of Data

While not significant statistically, diatom densities were over three times lower at the lower weir than the upper weir. This contrasts with data from 1978 and 1979 when densities at the two stations were generally higher at the lower weir (VTN Annual Report, 1979).

The density of benthic macroinvertebrates was significantly lower (P=0.05) at the lower weir compared to the upper weir in January 1980. Differences in species composition were also observed between this field trip and previous data. Baetis tricaudatus greatly dominated the fauna (88.8%) at the lower weir in January 1980. At the upper weir in January and at both weirs in February 1979, B. tricaudatus equaled between 1.0 and 16%. The lower weir in January 1980, had a sparser fauna of stoneflies, caddisflies, and Diptera than the upper weir or from samples of previous trips. Diatom species were similar at the upper and lower weir in January 1980. They did, however, vary from species identified from February 1979.

Discussion

The above differences suggest that changes in the invertebrate and periphyton communities have occurred at the lower weir since August 1979. Differences may be partially due to changes in sample location. In February 1979, samples at the lower weir were taken approximately one half mile further downstream than in January 1980, due to ice cover. In August 1979, samples were taken just upstream of the lower weir rather than below it as in January 1980. The different sites, however, appeared to have similar habitats and the fauna did not show obvious changes until this field visit.

It is possible that the differences in fauna observed during this trip were caused by sedimentation due to high spring flows in the creek and by channel repair in October. The substrate and banks were observed to be soft and unstable, and composed of small gravel mixed with sand and silt. These conditions are generally poor for invertebrates (Hynes, 1970). Seasonal and sample variation may also account for some of the differences. Water quality data for the upper and lower weirs were similar, and thus suggest no causes for the differences observed in the biota. In any event, the results from this field trip suggests all factors be carefully considered during future sampling.

References

Hynes, H.B.N. 1970. The Ecology of Running Waters. Liverpool University Press. 555 pp.

Patrick, R. and C.W. Reimer. 1966. The Diatoms of the United States, Vol. 1. Monographs of Acad. Mat. Sc. Philadelphia, 13:1-688.

____________________________. 1975. The Diatoms of the United States, Vol. 2. Monographs of Acad. Nat. Sc. Philadelphia, 13:1-213.

Table 1. Percent relative frequency of epilithic diatoms from Black Sulfur Creek collected January 15, 1980.

	Upper Weir	Lower Weir
Bacillariophyceae		
Coscinodiscaccae		
Cyclotella meneghiniana	0.6	0.004
Fragilariaceae		
Fragilaria sp.	1.2	0.5
F. vaucheriae		0.1
Synedra sp.	1.3	0.4
S. ulna	1.8	6.6
Achnanthaceae		
Achnanthes sp.	0.1	0.004
A. microcephala		1.1
A. minutissima	35.9	20.1
A. lanceolata	1.1	2.9
Cocconeis placentula	0.1	0.2
C. pediculus	0.5	1.5
C. diminuta		0.1
Rhoicosphenia curvata	0.02	0.1
Naviculaceae		
Frustulia vulgaris		0.004
Stauroneis smithii		0.004
Navicula sp.	0.5	0.1
N. viridula	14.3	22.3
N. arvensis	1.1	3.8
N. savannahiana	0.1	
N. tripunctata	0.8	
N. secreta	13.4	10.4
N. cryptocephala var. *cryptocephala*	0.015	0.7
N. cryptocephala var. *venata*	2.1	2.1
Gomphonemaceae		
Gomphonema sp.	0.6	1.1
G. olivaceum	2.6	12.5
G. olivaceum var. *calcarea*	2.1	4.5
G. intricatum var. *pumila*	0.015	
G. angustatum	0.2	
G. affine	0.1	0.004
Cymbellaceae		
Cymbella sp.	0.2	
C. minuta	10.6	5.5
C. affinis	1.2	0.4
C. sinuata	0.5	1.1
C. amphicephala	0.4	0.2
Amphora perpusilla	1.4	1.4

Table 1. (continued)

	Upper Weir	Lower Weir
Bacillariophyceae (continued)		
Nitzschiaceae		
Nitzschia frustulum	0.3	0.6
N. holsatica (?)	0.8	0.9
N. dissapata	2.6	1.0
N. apiculata	0.1	
N. vitrea (?)	1.1	0.004
N. amphibia		0.7
N. sp.	0.3	1.8
Surirellaceae		
Surirella sp.		0.1
S. ovata	0.02	0.004
Species	37	38
Diversity Index (Shannon-Weaver)	3.30	3.76
Eveness (J)	0.63	0.72
Average Total Density (cells/mm^2 $\pm$1 Std. Dev.)	6,990 $\pm$8,470	2,110 $\pm$2,750

Table 2. Mean density and percent relative frequency of benthic macroinvertebrates from Black Sulfur Creek collected January 15, 1980.

	Lower Weir		Upper Weir	
	$\bar{x}$ No/m^2 ± 2 Stdv.	%	$\bar{x}$ No/m^2 ± 2 Stdv.	%
EMPHEMEROPTERA		89.2		19.6
Baetidae				
Baetis tricaudatus	793±1,022	88.8	1,458±898	15.8
Baetis bicaudatus	4±12	0.4	274±441	3.0
Ephemerellidae				
Emphemerella sp.			70±46	0.8
PLECOPTERA		3.2		17.4
Capniidae				
Capnia	11±22	1.2	11±0	0.1
Nemouidae				
Zapada cinctipes	4±12	0.4		
Perlodidae				
Isoperla patricia	14±33	1.6	1,588±320	17.3
TRICHOPTERA		0.4		9.9
Glossosomatidae				
Anagapetus			253±76	2.8
Hydropsychidae				
Hydropsyche	4±12	0.4	640±1,142	7.0
Brachycentridae				
Brachycentrus sp.			5±15	0.05
COLEOPTERA		0.4		1.1
Haliplidae				
Brychius (larvae)			5±15	0.05
Elmidae				
Optioservus quadramaculatus (larvae)	4±12	0.4	65±0	0.7
Optioservus quadramaculatus (adult)			27±76	0.3
DIPTERA		5.2		52.0
Tipulidae				
Dicranota			27±76	0.3
Hexatoma	4±12	0.4	54±61	0.6
Limnophila	4±12	0.4	38±15	0.4

Table 2. (continued)

	Lower Weir		Upper Weir	
	$\bar{x}$ No/m^2 ± 2 Stdv.	%	$\bar{x}$ No/m^2 ± 2 Stdv.	%
DIPTERA (continued)				
Chironomidae (larvae)	36 ± 33	4.0	4,569 ± 6,317	49.8
Chironomidae (pupae)			43 ∓ 61	0.5
Empididae				
Chelifera (larvae)			27 ± 76	0.3
Strationmydae				
Euparyphus			10 ± 0	0.1
Muscidae				
Limnophora	4 ± 12	0.4		
HYDROCARINA				
Lebertiidae	4 ± 12	0.4	10 ± 0	0.1
GASTROPODA				
Limnaeidae	4 ± 12	0.4		
OLIGOCHAETA	4 ± 12	0.4		
PELECYPODA				
Sphaeriidae	4 ± 12	0.4		
Total Mean Density (No/m^2)	898		9,174	
No. of Taxa	16		20	
Species Diversity (Shannon-Weaver)	1.68		2.34	

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