BX IN SITU OIL SHALE PROJECT

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ABSTRACT

The BX In Situ Oil Shale Project, jointly sponsored by Equity Oil Company and the U. S. Department of Energy, has been in operation continuously since September 18, 1979. Between that time and February 28, 1981, 625,300 barrels (99,400 m^3) of water as steam have been injected into eight Project injection wells at an average wellhead temperature of 605°F. (318 °C.) and an average wellhead pressure of 1,314 psig (9,053 kPa). During the same period, 524,500 barrels (83,400 m^3) of fluid have been produced from five Project production wells. Steam injection has resulted in heating of the "leached zone" of the Parachute Creek Member of the Green River formation and this in turn has resulted in the in situ retorting of a portion of the oil shale of the "leached zone" and the recovery of a measureable amount of oil resulting from this retorting.

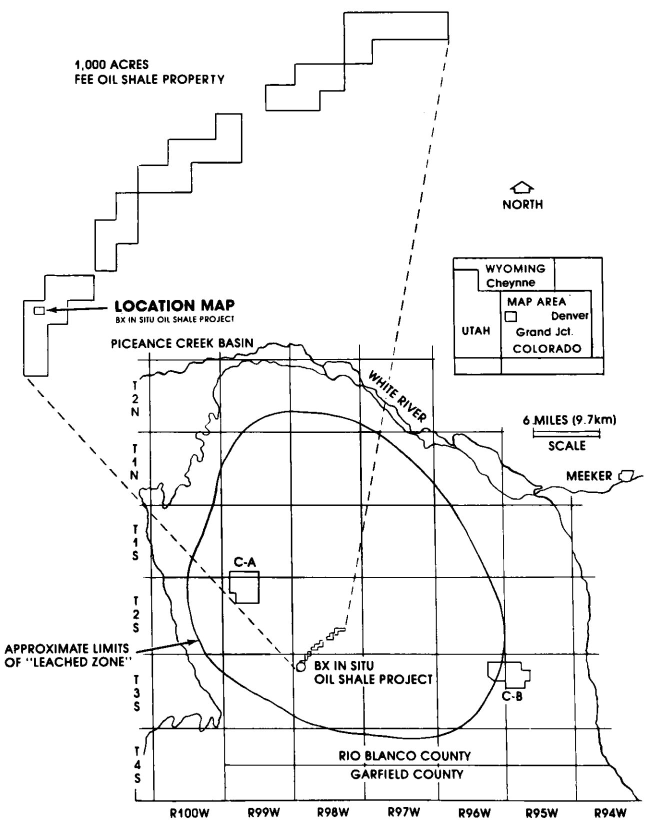
INTRODUCTION

The BX In Situ Oil Shale Project is based upon in situ oil shale research conducted by Equity Oil Company from 1962 through 1971.[1] The purpose of the present Project, jointly sponsored under a Cooperative Agreement between Equity Oil Company and the U. S. Department of Energy is to demonstrate the technical feasibility of using superheated steam as a heat carrying medium to retort in situ, oil shale of the "leached zone" of the Green River formation of northwestern Colorado, and provide a mechanism for the recovery of the shale oil produced with a minimum impact on the environment. The Project was begun in 1977 and initial field work; preliminary testing; site evaluation work; and Project design, construction and installation was accomplished between March 1977 and September 1979.[2] This paper includes a status report and a review of operational data from the project for the period September 18, 1979, through February 28, 1981, and an assessment of the project's goals and objectives.

Location & Geology

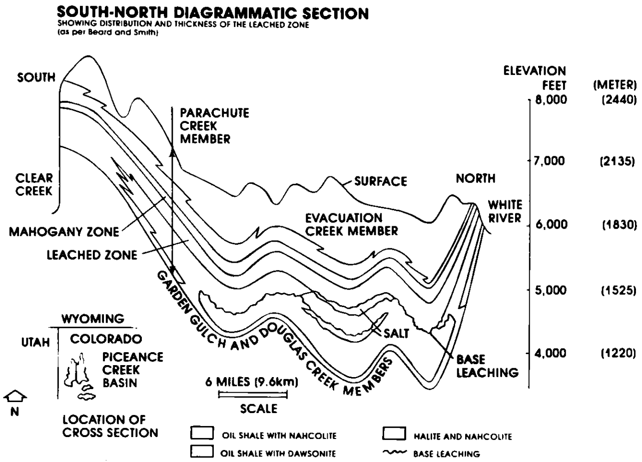
The Project site is located in the

FIGURE NO. 1



central portion of the Piceance Creek Basin of northwestern Colorado (Figure No. 1) on a 1,000 acre ($4x10^6 m^2$) fee property owned jointly by Equity Oil Company and Atlantic Richfield Company. The target zone for retorting is the "leached zone" of the Green River formation (Figure No. 2). At

FIGURE NO. 2



the Project site the zone has a thickness of 540 feet (165 m). The average yield of the oil shale in the "leached zone" at the Project site is 24 gallons per ton (100 L/t).

It is estimated that the property on which the present Project is sited contains 1,125,000,000 barrels ($1.79 \times 10^8 m^3$) of oil in place as oil shale, and that the total resources of the "leached zone" in the Piceance Creek Basin are 275 billion barrels ($44x10^9 m^3$) of oil in place as oil shale.

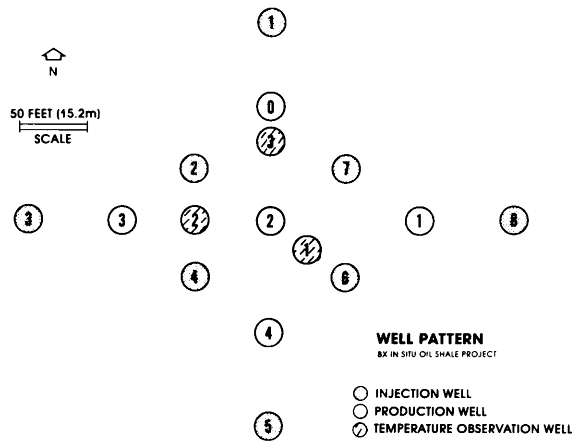
The "leached zone" derives its name from the numerous vugs or solution cavities present in the zone as a result of the leaching of salts present in the formation by ground water. These vugs, coupled with fracturing, give the zone native permeability and porosity which allows in situ retorting without resorting to other fracturing techniques.

A very large in place oil shale resource coupled with the native permeability and porosity of the "leached zone" and the fact that the porosity in the zone is filled with saline water has led to the development of the in situ retorting process presently being investigated at the Project site.

Project Design

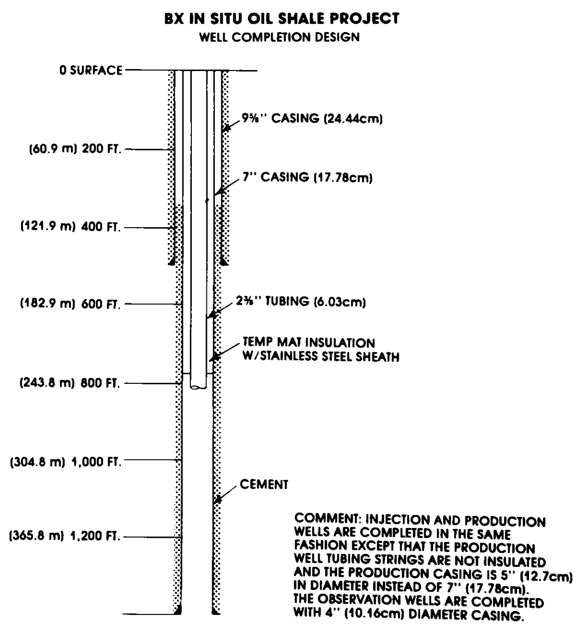
The present Project consists of a pattern of eight injection wells, five production wells and three temperature observation wells (Figure No. 3). The

FIGURE NO. 3



spacing between the wells is 68 feet (20.7m) from the injectors to the producers. Observation Wells No. 1 and No. 2 are spaced approximately half way between injection and production wells, and Observation Well No. 3 is located close to a production well.

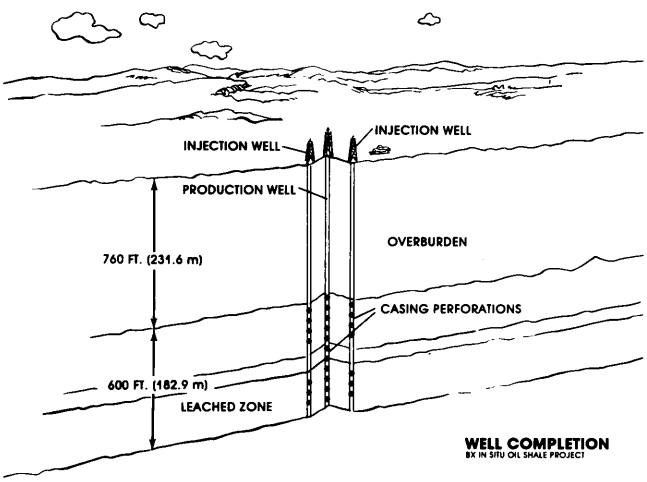
FIGURE NO. 4



All sixteen wells penetrate the entire "leached zone" and are drilled to a total depth of approximately 1,400 feet (427 m). The wells are completed as indicated in Figure No. 4.

The original Project design called for injection at the top and bottom of the "leached zone" and production from the central portion of the zone in a diagonal mode. Project operations have shown that there is insufficient vertical permeability to allow this mode of operation and, consequently, injection is being accomplished in both the upper and lower portions of the "leached zone" and the production wells are being produced throughout the entire "leached zone" (Figure No. 5). The injection and pro-

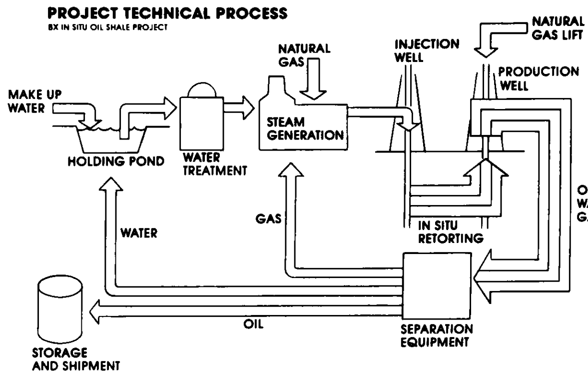
FIGURE NO. 5



duction wells are selectively perforated in the zones which indicate the highest degree of fracture porosity.

The Project design is as follows (Figure No. 6): Water is produced from the production wells and treated in an ion exchange water treatment plant to make it suitable for steam generation. Treated water is supplied to two steam generators which generate saturated steam and the dry steam fraction of the generated saturated steam is then fed to a superheater where it is raised to superheat conditions. Superheated steam is injected through the eight injection wells into the "leached zone" where the steam gives up its heat to the

FIGURE NO. 6



oil shale accomplishing the retorting process. Water, accompanied by produced oil and gas is produced at the production wells; after which the water is recirculated for use as feed water, the oil is stored to await shipment and the gas is added to the generator and superheater fuel supply.

The original Project design called for injection of superheated steam at 1,000°F. (538°C.), 1,500 psig (10,335 kPa) and a total pattern rate of 974,400 pounds (2,143,680 Kg) or 2,784 barrels (443 m^3) of water as steam per day. The overall Project goal was to inject continuously at these rates over a two-year period. It was recognized at the outset that these design goals were idealized, but they were established on the basis that over a two-year period, approximately 1 trillion BTU (1.06×10^{15} J) of heat would be injected into the Project well pattern which covers .7 acres (2833 m^2) and has a total volume of approximately 16.4 million cubic feet (464,100 m^3). This volume of oil shale contains approximately 652,000 barrels (103,700 m^3) of oil in place as oil shale. Shale oil has an average heating value of 5.98 million BTU/barrel (3.97×10^7 kJ/m^3). Therefore, the in place energy resource at the Project site is approximately 3.89 trillion BTU (4.10×10^{15} J) or 3.89 times larger than the planned heat injection.

PROJECT STATUS

Although original Project plans called for continuous injection of superheated steam at 1,000°F. (538 °C.), 1,500 psig

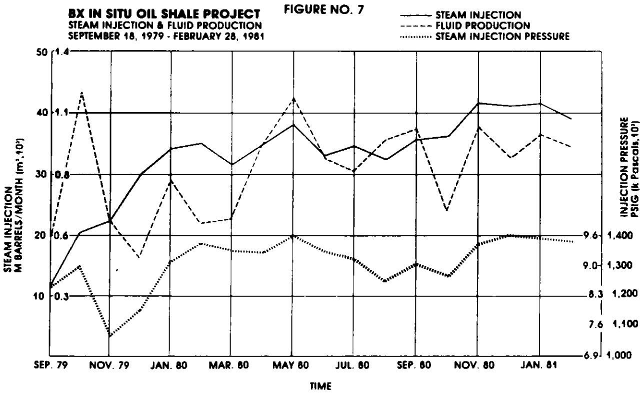
(10,335 kPa) and an average daily injection rate of 2,784 barrels (443 m^3) per day, a variety of problems, principally mechanical, with Project surface equipment have not allowed the Project to proceed as planned.

Injection & Production History

Between September 18, 1979 and February 28, 1981, 625,300 barrels (99,400 m^3) of water as steam were injected into the eight Project injection wells at an average daily injection rate of 1,202 barrels (191 m^3) per day, a weighted average wellhead injection temperature of 604 °F. (318 °C.) and a weighted average wellhead pressure of 1,314 psig (9,053 kPa). During this same period, 524,500 barrels (83,400 m^3) of fluid have been produced from the five Project production wells at a daily average rate of 1,012 barrels (161 m^3) per day. Injection, production, injection temperature and injection pressure are presented in Table I for each month of the period.

The relationship between steam injection volume and fluid production is plotted in Figure No. 7. This plot shows

FIGURE NO. 7



that total production has exceeded total injection in only three months of the injection period. A basic premise of the process is that water required for injection as steam will be produced from the "leached zone" and that the process will require no consumptive use of water. Through February 28, 1981, the ratio of produced to injected water is .84 to 1.0. To overcome this imbalance, the producing wells have been or are being modified to increase their productive capacity. These modifications have included the installation of higher volume downhole pumps and the addition of more wellbore perforations in each of the production wells. All wells have been perforated and three of the wells are now equipped with downhole pumps. Installation of downhole pumps are scheduled for the other two production wells in April 1981. Initial data for March indicates a fairly steady ratio of produced to injected water of 1.07 to 1.0.

Injection pressure by month is also plotted in Figure No. 7 and as would be expected, the sensitivity of injection volume to injection pressure is clearly demonstrated. The initial goal of injecting at 1,500 psig (10,335 kPa) has not been possible due to line losses between steam generating equipment and the injection wellheads. With present equipment, experience has shown that a realistic sustained injection pressure is 1,400 psig± 1% (9,646 kPa). If this pressure is maintained through the balance of the planned injection period (through January 1982) and if a positive balance of production over injection can be maintained, injection at or above 1,350 barrels (215 m^3) per day is expected for the balance of the period.

Data from site evaluation work done early in the Project indicated that the horizontal permeability in the "leached zone" is approximately 14 times greater than the vertical permeability and that preference to flow in the horizontal direction was essentially isotropic.[3] Temperature increases resulting from actual steam injection have generally confirmed this data, although there is a fairly broad range of injection and production rates in the individual injection and production wells. Table II presents the data for injection, production, injection pressure and injection temperature on a per well basis for February 1981. The relative performance of the injection and production wells as observed for this month is repre-

Table No. I
BX In Situ Oil Shale Project
Injection Data
September 18, 1979 - February 28, 1981

MONTH	NUMBER OF INJECTION DAYS	TOTAL INJECTION BARRELS[1]	CUMULATIVE TOTAL INJECTION, BARRELS[1]	AVERAGE DAILY INJECTION RATE, BARRELS/DAY[1]	DAILY AVERAGE INJECTION TEMPERATURE, °F.[3]	DAILY AVERAGE INJ. PRESSURE, PSIG[2]	TOTAL PRODUCTION, BARRELS[1]	CUMULATIVE PROD., BARRELS[1]	DAILY AVERAGE PRODUCTION, BARRELS/DAY[1]
1979									
September	13	18,549	18,549	1,426	541	1,235	10,140	10,140	780
October	31	43,527	62,076	1,404	514	1,303	20,432	30,572	729
November	26	22,197	84,273	853	471	1,063	22,100	52,672	850
December	31	30,051	114,324	969	494	1,149	16,596	69,268	535
1980									
January	31	34,218	148,542	1,103	465	1,314	29,045	98,313	937
February	27	35,048	183,590	1,298	472	1,371	22,382	120,695	772
March	31	31,550	215,140	1,017	484	1,355	22,790	143,485	735
April	30	34,590	249,730	1,153	489	1,346	34,790	178,275	1,159
May	31	38,898	288,628	1,254	574	1,398	43,220	221,495	1,394
June	30	33,226	321,854	1,071	756	1,355	32,898	254,390	1,061
July	31	34,761	356,615	1,121	731	1,324	30,776	285,166	992
August	31	32,419	389,034	1,045	605	1,248	35,877	321,043	1,157
September	25	35,929	424,963	1,437	540	1,312	*37,387	358,430	1,246
October	31	36,363	461,326	1,173	604	1,265	**23,660	382,090	876
November	30	41,880	503,206	1,396	766	1,376	37,660	419,750	1,255
December	31	41,415	544,621	1,335	752	1,400	33,252	453,002	1,040
1981									
January	31	41,720	586,341	1,345	784	1,395	36,560	489,562	1,179
February	28	39,000	625,341	1,392	776	1,386	34,892	524,454	1,246

*30 production days
**27 production days

[1] Barrels x .159 = cubic meters
[2] PSI x 6.89 = kPascals
[3] 1°F. = 1.8°C. +32

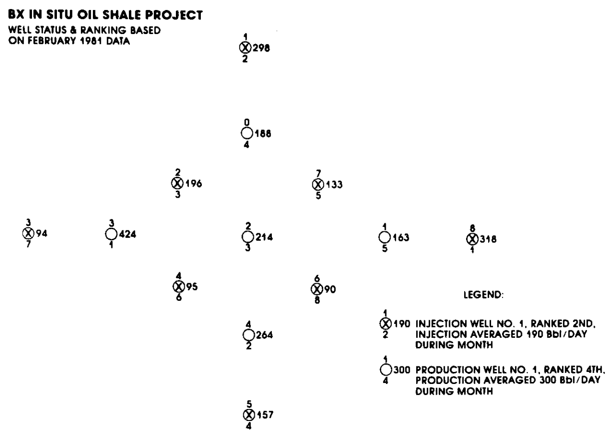
Table No. II
BX In Situ Oil Shale Project
Well Performance Data
February 1981

	AVERAGE DAILY INJECTION OR PRODUCTION, BARRELS/DAY[1]	AVERAGE DAILY WELLHEAD TEMPERATURE, °F.[3]	AVERAGE DAILY WELLHEAD PRESSURE, PSIG[2]	TEMPERATURE @ 840 FEET, °F.[3]
INJECTION WELLS				
1	298	778	1,317	
2	196	787	1,409	
3	94	732	1,410	
4	95	746	1,386	
5	157	785	1,406	
6	90	741	1,408	
7	133	812	1,407	
8	318	829	1,358	
PRODUCTION WELLS				
0	188	80		
1	163	78		
2	214	80		
3	424	110		
4	264	89		
TEMPERATURE OBSERVATION WELLS				
1			84	388
2			1,206	333
3			972	394

[1] Barrels x .159 = cubic meters
[2] PSI x 6.89 = kPascals
[3] 1°F. = 1.8°C. +32

sentative of the wells' behavior for the Project operations to date. Figure No. 8 is a plot of Project wells based on February 1981 data showing their relative ranking as an injector or producer.

FIGURE NO. 8



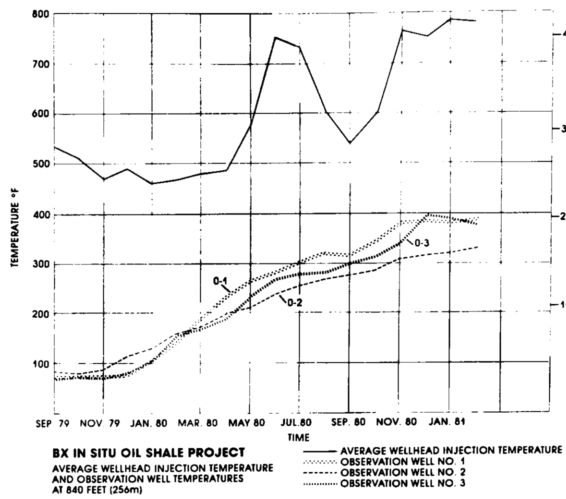
Temperature History

The Project was set up with three temperature observation wells, each containing a bundle of thirty-five thermocouples. These thermocouples were banded to the outside of 4½ inch (11.4 cm) casing and cemented in place. The first five thermocouples are placed at 450, 500, 600, 700 and 760 feet (137, 152, 183, 214 and 232 m). The balance of the thirty thermocouples are equally spaced at 20-foot (6.1 m) intervals to a total depth of 1,360 feet (415 m). Data from the observation wells is logged continuously by a data logger which permanently stores an average value for each point being monitored every four hours.

The thermocouples in each of the observation wells performed satisfactorily during the initial five months of injection but in March of 1980 thermocouples below 860 feet (262 m) in Observation Wells No. 1 and No. 3 failed. And in August the thermocouples below 900 feet (274 m) in Observation Well No. 2 also failed. To supplement the data collected from the thermocouples, temperature logs have been run at different times in the observation wells and in the producing wells.

Figure No. 9 plots the average injec-

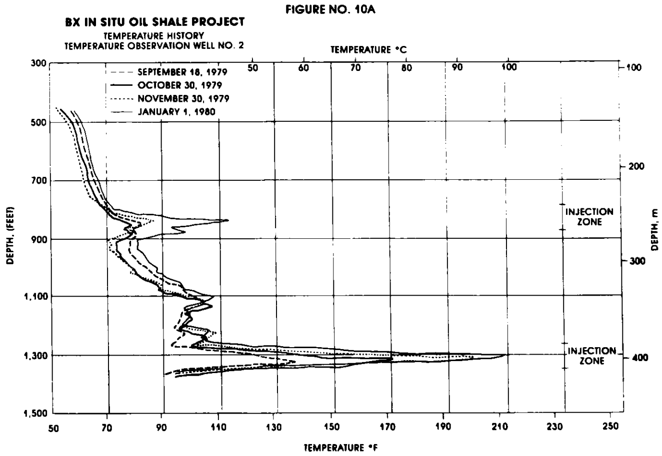
FIGURE NO. 9



tion temperature and the temperature of the 840 foot (256 m) level in each of the three observation wells as a function of time. As shown in this graph, the temperature at the 840 foot (256 m) level in each of the observation wells has increased at approximately the same rate, thus verifying the isotropic nature of the "leached zone" in a given horizontal plane.

Figure Nos. 10a, b and c plot the temperature history for Temperature Observation Well No. 2 from September 18, 1979, to July 31, 1980. The behavior of the temperature front in this well is very similar to that observed in Observation Wells No. 1 and No. 3 prior to the time the thermocouples failed.

FIGURE NO. 10A



Temperature logs have been run in the observation wells to verify readings recorded by the thermocouple bundles. These logs show the same heating pattern

FIGURE NO. 10B

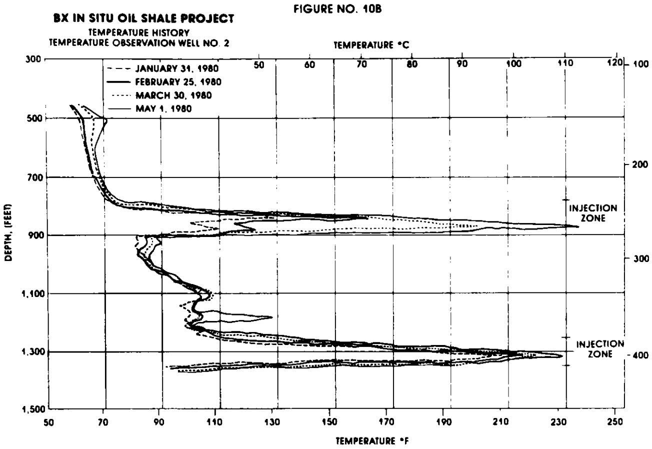
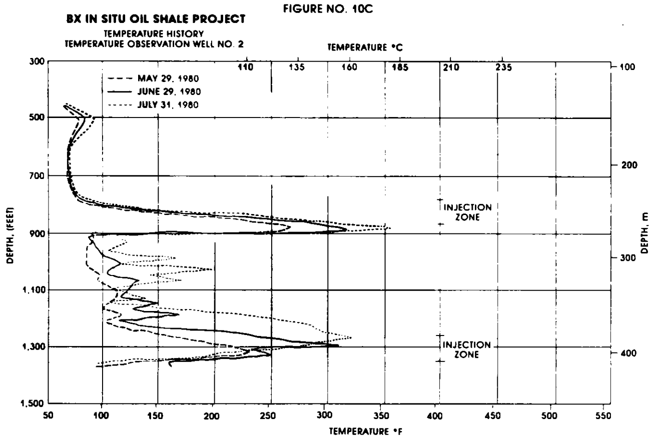
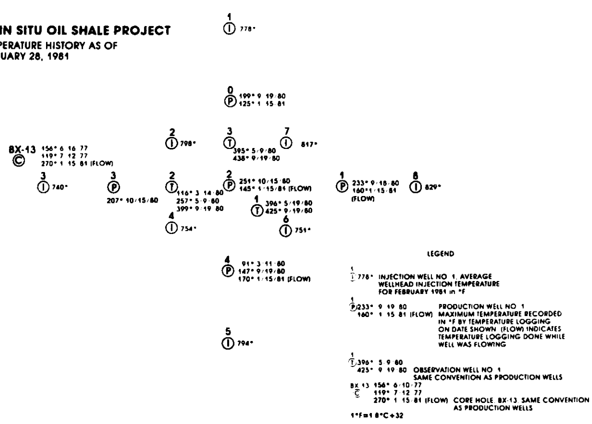


FIGURE NO. 10C



as that recorded in the observation wells. In each case, the maximum heating has occurred in the two injection zones at the top and bottom of the "leached zone" with a lesser amount of heating taking place in the middle of the zone. Figure No. 11 plots for each well the date the temperature log was run and the maximum temperature recorded during the logging.

FIGURE NO. 11



Oil Recovery

In October, 1980, the first retorted oil was recovered from Production Well No. 0. Subsequent to that date, oil has been observed in each of the producing wells and through February 28, 1981, 46 barrels of oil have been recovered. Given the average wellhead injection temperature through February 28, 1981, of 605°F. (318°C) and a maximum observed formation temperature of under 440°F. (227°C.) in the observation wells, it is clear that the oil liberated to date has been produced at very low temperatures and its characteristics verify this. In Table III the qualities of the field produced oil are compared with oil produced by low temperature steam retorting at the University of Utah.[4]

CONCLUSIONS

The following conclusions can be reached from operations of the BX In Situ Oil Shale Project through February 28, 1981:

1. Superheated steam can be injected into the "leached zone" at a reasonable rate which is principally controlled by injection pressure, the number of perforations in the injection well, and the withdrawal rate by production from the "leached zone." While the design temperature of 1,000°F. (538°C.) is not being met, the present average injection temperature of 776°F. (413°C.) is adequate to retort oil shale in the "leached zone."

2. When superheated steam is injected into the "leached zone" the steam gives up its heat to the zone and appears to move out from the injection wells in a principally horizontal direction and in a basically isotropic fashion.

Table III
BX In Situ Oil Shale Project
Oil Quality Comparison

	FIELD PRODUCED OIL	LABORATORY PRODUCED OIL*
API Gravity	19.4°	15.9°
Pour Point	115°F. (46°C.)	81.5°F. (28°C.)
Elemental Analysis		
C	83.91%	82.8%
H	11.24%	11.7%
N	2.28%	0.92%
S	0.46%	--
O	1.34%	4.34% (S+O)
Ash	0.77%	N.A.
C/H Ratio	7.47	7.08

*Produced in a 200-hour steam retorting run at a pressure of 425 PSIG (2.93 kPa) and a temperature ranging from 513°F. (267°C.) to 585°F. (307°C.).

3. Formation heating in the "leached zone" by superheated steam injection has resulted in the in situ retorting of some of the oil shale in the "leached zone" and the evolved oil has appeared in measureable quantities at Project production wells.

4. Oil produced to date by in situ retorting in the field has physical properties similar to those of oil produced in a laboratory experiment run to simulate actual field experience.

The Project is presently scheduled to continue operations through January 1982. The goal for the remainder of the injection period is to maximize steam injection rate, injection temperature, fluid production rate, and oil recovery. If present trends continue, it is expected that adequate data can be collected by January 1982 to evaluate the technical feasibility of the process.

Literature Cited

1. Dougan, P.M., Fred S. Reynolds, and Paul J. Root, "The Potential For In Situ Retorting of Oil Shale in the Piceance Creek Basin of Northwestern Colorado," 6th Annual Oil Shale Symposium, sponsored by AIME and Colorado School of Mines, Denver, Colorado (1969).

2. Dougan, P.M., "The BX In Situ Oil Shale Project," Chemical Engineering Progress, Vol. 75, No. 9, September 1979.

3. Dougan, P.M., "Site Evaluation Report, BX In Situ Oil Shale Project," performed under Contract No. ET-78-F-03-1747 with Department of Energy, dated November 11, 1977, Report No. FE-1747-T1 published by U.S. Technical Information Center.

4. Jacobs, Harold R., Martin J. Marzinelli, Kent S. Udell and Paul M. Dougan, "Laboratory Modeling of In Situ Retorting of Oil Shale From the "Leached Zone" of the Parachute Creek Formation by Superheated Steam Injection," pages 62-73 of the Proceedings of the Thirteenth Oil Shale Symposium, published by Colorado School of Mines press August 1980.