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A DESIGN FOR A CAUSTIC FLOOD BELL CREEK OIL FIELD UNIT E POWDER RIVER COUNTY MONTANA

by

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ABSTRACT

The potential for a caustic flood has been investigated for the Unit E Muddy Sand, Bell Creek oil field, Powder River County, Montana. The project consists of infill drilling four 160-acre patterns, conversion of those patterns to normal 5-spot injection from the current line-drive waterflood and conducting tertiary (caustic flood) operations using sodium hydroxide and sodium metasilicate. The reserves expected to be produced are 435,000 barrels of oil (BO), 342,000 of which are attributed to existing and expanded waterflood activities and 93,000 BO are attributed to the addition of caustic. The 93,000 BO represents 4% additional recovery of the original oil-in-place in the reservoir lenses which have been water flooded to a residual oil saturation. A higher incremental recovery could be expected in the lenses that are not at residual oil saturation.

The flood is designed to be conducted using produced water which is chemically softened by a direct precipitation technique, thereby saving the expenses associated with a zeolite water softener, de-oiling units, and associated facility costs.

A design of the facilities to prepare the caustic slug is presented along with an analysis of core data,

coreflood procedures, economic evaluation and a discussion of regulatory requirements.

The fluids were analyzed by Exoil Services; O-Tech, Inc., and Dr. Weinbrandt, EOR Consultant. The rock and caustic design have been analyzed by PQ Energy, Petroleum Testing Services, B-1 Industries, AGAT Consultants and Dr. Weinbrandt.

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The work of Exoil Services, PQ Energy Services in coreflooding, Petroleum Testing services in core flood procedures, B-1 Industries in core analysis, AGAT Consultants in petrographic analyses, O-Tech in flood water testing, and Dr. R. E. Weinbrandt in caustic flood design were used extensively.

INTRODUCTION

The Bell Creek oil field, which is located in Powder River County, Montana (Figure 1) was discovered in 1967. The zone of interest is called the Bell Creek Sand and is in the Muddy sequence in the Powder River Basin (type log, Figure 2). The sand is considered to be a beach sand, deposited by a transgressive sea (4). The field was unitized by the end of 1971 for a line-drive waterflood conducted on 160-acre spacing. Unit E responded to the line-drive, but the performance was not as good as experienced in other units. The depositional environment of Unit E is considered to be lagoonal to shallow marsh, and the sand is not as clean, or as continuous, as the beach sands of Unit A (5).

A 160-acre area was selected in Unit E for 4 infill wells. The wells were drilled in 1980 (Figure 3) and cores were obtained from two wells to assist in the review for suitability for alkaline flooding.

Although the data indicate Unit E is not an extremely favorable candidate (6), there is sufficient evidence in the suitability of the oil, rock and water to alkaline flooding to proceed with the design.

A caustic flood in Unit E has been designed to use produced water (oil field brine) which has been chemically softened by direct precipitiation of the hardness ions using a small amount of sodium hydroxide. The water then is spiked to flood concentration of 2% of sodium hydroxide and sodium metasilicate (this is the "caustic" or alkaline flood fluids) and then injected into seven converted injection wells. The result is four normal 5-spot patterns, each of 40 acres, from the existing 160-acre line-drive flood. The two north corner wells should be water-only injectors, rather than caustic injectors due to the poor reservoir continuity with the rest of the pattern. The corner wells should provide hydraulic support to prevent alkaline drift outside of the desired area, but little flood drive.

The pore volume to be flooded by caustic is 3,130,000 barrels (3.13 MMBLS), which represents the summation of the connected lenses. The total project recovery is expected to be 435,000 barrels of oil (BO), of which 342,000 are due to waterflood response and 93,000 BO are due to caustic displacement.

The field was reviewed for suitability for alkaline flooding by first reviewing the literature for tests available (reference 7 through 23) and then performing selected tests. The chemical reactions occurring during caustic displacement are not fully understood, and some evaluation procedures can consume more revenues in the laboratory than can be produced by the process in the field.

SUMMARY

The use of a direct precipitation reaction (DPR) method of water softening is an important element of the project development. The option of using zeolite water softeners and the associated facilities and operating costs could have put the project economics into an unacceptable range. The direct precipitation reaction method takes advantage of the water most readily available which, by coincidence, requires the least volume of chemicals to treat. A very similar method (1) has been in use by a major oil company at a west Texas alkaline flood since 1979.

Unit E was selected as a candidate flood because of the high (in comparison to Unit A) residual oil saturation. This "tertiary target" oil became a target as a result of an infill drilling program which intercepted some discontinuous sand lenses. The oil and rock reactions with alkaline material are considered "fair" at Unit E (2,3). If the results of the project are also "fair," then there are many potential Bell Creek waterflood patterns which could be expected to perform better.

CONCLUSIONS

1. The direct precipitation reaction (DPR) method of chemically softening water is applicable to the produced oil field brine available at Unit E.

2. The reactivity of the oil with alkaline materials (sodium hydroxide and sodium silicate) indicates an acceptable reduction in interfacial tension (IFT) (from 10.0 to 0.2 dynes/cm) at a concentration of 0.2% alkaline in slightly salty water (2000 ppm NaCl). This interfacial tension reduction is "fair" to "good."

3. The Berea core floods performed with simulated DPR water and Unit E oil were acceptable and consistent with flood results obtained for other floods which were successful (recovered greater than 4% of the original oil-in-place with aklaline flood beginning at waterflood residual).

4. The core analysis and petrographic studies performed have indicated that the rock chemical and depositional configuration do not preclude the proposed flood.

5. Core flooding with Unit E oil, rock, and water would not answer the caustic consumption or ultimate field recovery questions for a reasonable cost.

6. The overall project economics are favorable.

SECTION I

RESERVOIR DESCRIPTION

Background and History

The Bell Creek oil field discovery well was the 33-1 Federal-McCarrel in NE, NE Sec 33-T8S-R54W and was completed June 29, 1967. In the Fall of 1967, forty-acre spacing was designated for Bell Creek. Production peaked in August 1968 at 1.7 MMBOPM field total. Bell Creek Unit 'E' became unitized in December 1971 for line-drive waterflood operations.

The Bell Creek Sand is encountered at approximately 4,300 feet (KB) (795 feet Sub-Sea) between the Muddy silt and the Skull Creek formations, in the Powder River Basin, Montana (Figure 1).

The Bell Creek Sand is divided into two major zones, Zone 1 (upper) and Zone 2 (lower) (Figure 2). Unit 'E' contains eight correlatable sands of the 26 mappable productive sand bodies within the Bell Creek Field. Six of these sands overlap and are interconnected through 50 of the 65 wells within the area. The remaining two sands are interconnected by the other 15 wells.

Fourteen lithologic units were identified in a petrographic study (5) on well 13-22 and seven units were identified in well 13-28. Three of the major lenses are correlatable in the caustic flood Unit 'E' (CFE).

Each of the sand bodies are stratigraphic traps resulting from facies changes. Water properties have changed due to waterflooding with Madison water. Oil properties have been significantly different ($\pm$ 5° API) across the field and chronologically from within the same well, apparently due to production from different lenses at different times.

Reservoir Volume Development

The logs were correlated on a fence diagram cross section (Figure 4--in map pocket). The correlation was first bracketed by the top of the Muddy Sand and the top of the Skull Creek formation. Three zones were identified--the Upper, Lower and Basal Muddy. The separation between these upper units is a well-developed coal stringer identifiable in wells 13-6, 13-22, 13-27, 13-21, 13-28, 13-11, and 13-12. The pick is not distinct in the other wells. The basal zone is perforated in wells 13-3 and 13-21 only.

Gross thickness, net thickness and porosity of each zone were calculated form the logs. Intensive log evaluation research conducted in Unit A under a Government sponsored "Residual Oil Saturation" test concluded that the porosity determined from the density log is the most reliable porosity measurement and that the log reading can be used without correction. Most wells in the CFE area had density logs. Log-derived water saturations were not considered applicable because the wells were logged prior to the passage of the waterflood banks. The net pay was determined in a lense that is connected between injector and producer. If an injector had a perforated porous zone connected to another injector but not to a new producer, no net pay was assigned. If the zone was perforated and connected, the log porosity and perforated zone were considered pay. Producing well porosity-thickness (ØH) was calculated on net pay for zones with greater than 17% porosity. Injection well ØH was selected on Ø greater than 15%, or perforated zone.

The injector porosity cutoff was chosen to be lower than the producer cutoff because the injector may accept and displace fluid to the producer in zones that would not flow under natural drainage to the producer. There were zones open in some producers that were not connected to injectors.

The results of the log evaluation are tabulated in Table 1--Zonal Volume Upper, and Table 2--Zonal Volume Lower.

The CFE pattern ØH was arithmetically averaged between injector and producer per zone. This average ØH was then used to calculate pore volume and original oil-in-place at the original oil saturation (75.3%). The average value for net pay and porosity are backed out of the total ØH.

The cumulative production and injection of each well was allocated to the project, pattern and zone. This were compared to the calculated oil-in-place and expected ultimate recovery. The work can be tracked through Tables 3 and 4, Pattern Pore Volumes, Table 5, Cumulative Production, Tables 6 through 9, Production Predictions and results in Table 10, Combined Production Predictions.

These tables are summarized on the Reservoir Data Sheet, Table 11.

Table 1 is organized into four rows of six columns. The rows are for each 5-well pattern; the first three entries in each column are individual well data. The last entry (ØH ave.) is the arithmetic average between the center producing well (Column 1) and the individual injector. Column 6 shows the average properites of the pattern. The zonal average properties of all patterns is indicated at the bottom.

Table 2 is organized identically to Table 1 and addresses the lower zone of the Muddy Sand and the basal zone. Table 3 summarizes the net volume determined in Tables 1 and 2 for the upper and lower sands in the north two patterns. The volume is in reservoir barrels of pore volume. Also, the project allocation factor is presented. This is the fraction of injection (or production) that enters a well that is attributed to the project. As an example, well 13-3 is an edge well, so one-half of the injection would be in the project, one-half out, if the well encountered ideal radial pressure distribution, so the "project factor" is 50%. Next, the upper lense volume is 91% of the entire pore volume of that well, so the "zone upper" is 0.91 and "zone L" is 0.09. The well is also serving two patterns--well 13-22 and well 13-21, and again the ratio of pore volumes into each pattern is calculated to arrive at the "pattern factor" of 0.49 to the well 13-22 pattern. Applying the pattern and project factors to the zone factor achieves an overall "factor" for the upper and for the lower zone. These sum to the total factor. This is repeated for each well in the north patterns (wells 13-22 and 13-21) on Table 3 and in the south patterns (wells 13-27 and 13-28) on Table 4.

Table 5 presents the total sales from each project well. The monthly production per well prior to unitization in late 1971 was not available. The injection volume on the two existing injectors is also reported. Wells 13-2 through 13-12 are scheduled to become injectors in the project.

Table 6 takes the total sales from each well in one pattern and applies the allocation factor from Tables 3 and 4 to calculate the allocated production from each zone. This allocated production is then compared to the estimated original oil-in-place per zone and a zonal condition is selected based on the degree of recovery. A formation-volume-factor of 1.0 was used in predicting future reserves. This should not be a significant variation from the actual, and unknown, volume factor determined at the current bubble point of approximately 50 psig.

If the recovery as a percentage of OOIP were greater than 40% (the field average recovery at abandonment) then the zone was judged fully swept and no additional waterflood reserves are added. However, 4% of the OOIP is added to reflect caustic recovery, regardless of the calculated waterflood residual. Well 13-2 is so poorly connected to the pattern that no reserves are attributed. The ultimate recovery in the zones considered partially swept was calculated from either (1) the difference between the current cumulative production and 40% of OOIP, or (2) equal to the cumulative production, whichever is lower.

The total remaining reserves from waterflood (WF) and from caustic flood (CF) is then totalled per zone, per well and per pattern. Tables 7, 8 and 9 each present one pattern of reserve prediction. Table 10 summarizes each pattern by zone for waterflood and for caustic flood reserves. As a consequence of the development of these tables, the contribution of well 13-2 and well 13-4 to caustic recovery was considered not to be worth the chemicals to be injected and were eliminated from the 160-acre pattern. The resulting pattern is 140 acres. There may be some hydraulic support benefit from injecting only water into these corner wells. The support may prevent drift of the chemicals from the adjacent injectors into areas not likely to be productive.

The tertiary target pore volume was calculated to be 3.13 MMBBLS. The volume of chemicals needed to achieve a statutory flood is 1,565 BBLS into the target pore volume

(500 PPM/PV is DOE minimum). The allocation factor was then applied to determine that the total well injection volume needed was 3,155 BBLS of active material.

Core Analysis

Routine Core Analysis

Two infill wells, 13-22 and 13-28, were cored through the Muddy sandstone. B-1 Industries slabbed the core material recovered from 13-22 and 13-28 and produced split-frame photo-strips. A wide range in log characteristics was found which is consistent with the core description. The B-1 analysis includes a surface Gamma Ray for correlation purposes. Based on correlations to the center of the radioactive coal, the core recovery lost a foot of material in 13-22 @ 443' (core). The rest of the core material correlates well with the logs. The porosity ranges from 16% to 24% and permeability (air) ranges between 100 and 500 md in well 13-22. Well 13-28 ranges between 100 and 500 md and 12 to 27% porosity. The analysis is Appendix 1 and 2.

Petrographic Core Analysis

AGAT performed a petrographic study and identified 14 depositional environments in well 13-22 three of which correlate to the seven dispositional environments in well 13-28. Migrating clays (kaolinite) have been seen in the

SEM work to cause "brush heaps" in some pores, possibly as damage from the 10 years of fresh water flooding. They recommended clay stabilizers be used. The lateral continuity was judged to be fair to good in the lower lenses and poor in the upper lense. The upper lense has sufficient clays to deactivate large quantities of caustic, but due to poor continuity are not likely to take large volumes of fluid. AGAT found swelling clays and recommends no fresh water be injected. Unit E has been flooded with fresh Madison water since 1971, and the design is to use soft "fresh" produced water for the caustic flood.

Core Floods

Flood Results

Core floods were performed by PQ Energy Services to determine if the water type and caustic concentrations selected from IFT work would perform in core flood work as predicted (Appendix 3). Their work confirmed that the optimum slug is 0.5 wt% caustic injected for 40% of a pore volume. However, due to consumption of caustic by rock contact and by contact with hard water ions in the formation, a higher inlet concentration is planned (2%). Various slug sizes were tried, ranging from a continuous injection for 2.9 to a 4.3 pore volume slug size.

The uncertainties of reservoir continuity suggest that the best economics will be to inject the minimum volume and then continue to inject until either a lense breaks through (detected by increasing silicate content) or the maximum slug is injected. The minimum slug size is determined by the Department of Energy as 500 ppm/pore volume of active alkaline material. The maximum slug size is continuous injection of alkali, and tests indicate there is no difference in recovery when injecting continuous or injecting 40% of a P.V. slug. Detection of pH response is not likely to be useable as a detector of flood-front breakthrough. Silicate should travel through the reservoir ahead of the pH bank and be the first indication of flood arrival.

Proposed Additional Floods

A comprehensive flood procedure was designed by the author to obtain comparable results between a lab testing silicate and a lab testing hydroxide flood alternatives. The flood procedures are attached as Appendix 4. The cost of performing the procedure would have been $100,000 at Petroleum Testing Services plus an additional lab fee for continued work at PQ. A simplified procedure was suggested by Exoil at $25,000. The results of the additional flood work would be very interesting, but would not necessarily improve the slug design or the field recovery. As such, I am recommending that no more testing be performed.

Oil Analysis

Dr. Weinbrandt reported the results of Jar tests and IFT measurements on Unit E oil. The oil performed far better than the Ranch Creek oil field (a southern extension of Bell Creek) but not as well as Unit A, a northern portion of Bell Creek, demonstrating Instantaneous IFT reductions from 10 to 0.2. This reduction is not as great as some oils, but judged to be quite adequate for our use.

Exoil Services also performed IFT studies, but used water which was harder than used by Weinbrandt. IFT is sensitive to hardness ions and so the results gave a range of hardness which can be tolerated. Madison water has approximately ten times the concentration of hardness ions as does produced water and would require ten times the ion exchange bed volume as produced water. Produced water has an oil and grease content which would poison an ion bed and the savings in ion bed volume would be lost in a de-oiling unit if ion exchange bed units were to be used.

PQ Energy Services also did IFT work and used a different technique than did Weinbrandt (Appendix 3). The PQ method adds alkaline solution to the oil droplet and observes the IFT at 2 minutes, 5, 10 and 15-minute time intervals. The reported IFT is the average of these four readings. Weinbrandt reported the instantaneous minimum as the IFT required for displacement. PQ's average is a good value for the tendency to maintain mobilization and prevention of re-trapment. PQ's values were not as low as Weinbrandt's but lower than Exoil's. No IFT was particularly dramatic but all were encouraging.

Water Analysis

Exoil's water analysis report helped determine the size of ion exchange bed needed to use Madison water from the Ranch Creek Madison supply well and to compare that system's cost to the pit water blend available at Unit E. The blend is approximately 60% to 80% produced water from the water-knockout system and the remaining 20% to 40% is make-up water from the Madison formation. The elimination of all Madison water from the produced water system resulted in a water beginning with 44 ppm total calcium carbonate hardness, a value softer than most domestic water supplies. This fairly soft water is then softened more by the reaction between caustic and calcium/magnesium.

A field-scale water softening test was performed in May 1981 at Unit E. The hardness was observed to decrease from 44 to 33 ppm (3 parts Ca, <1 part Mg) upon sufficient contact with caustic. This level is better than the leakage experienced through most bed systems.

SECTION II

SUITABILITY FOR CAUSTIC FLOODING

The technology of caustic flooding is not a mature science and there are controversial positions as to which mechanisms of recovery dominate in the increase of oil production. The areas generally agreed on are that there are reactions between alkali and rock which cause wettability reversals in both directions (2,3,13,16,21,22) and consequent displacement in reservoirs with high gravity oils; and that there are reactions between alkali and certain acids contained in some oils which produce a soap which creates emulsification between oil and water. Both are likely to occur in Unit E.

The oil which is emulsified generally becomes more viscous than the native oil. Native oil travels from pore-to-pore in droplets. The emulsified oil travels in a ganglia flow, pausing at a pore throat and necking through as smaller ganglia gather in a large blob. Occasionally, the emulsion will form a diaphram over several pore throats and momentarily divert the water to new courses.

The emulsion is formed by a reaction between alkali and certain acids in the oil. Various combinations in the concentration of the acids and the concentration of the alkali can generate small, mobile ganglia, or chemically burn the oil and form large sticky immobile ganglia.

The type of native acid (or blend of acids) is not known. One test for existence of the blend of active acids is known as the Total Acid Number (TAN) which is determined as the milligrams of potassium hydroxide (KOH) required to neutralize the oil sample. This test is indicative of acid content and generally the higher the TAN, the better the caustic flood candidate. This is not a conclusive test, as some oils can exhibit a low TAN and still be very reactive to alkali (1).

The reactivity is measured by Interfacial Tension Tests (IFT). Laboratories differ on the technique used in IFT determinations. One method is time averaged IFT, where a measurement is taken at 1 minute of contact time between oil and caustic, another at 5, 10 and 30 minutes (7). Some investigators believe that displacement will occur at the instantaneous minimum IFT, and future increases in IFT represent, not displacement, but a tendency for oil to become trapped in some ensuing pore throat (retrapment)(15,18).

The reduction in IFT allows the oil droplet to be invaded by water, swelling and displacing the droplet from its place of residence. This displacement of small droplets into an aqueous medium is called emulsification. It is one of several displacement mechanisms thought to occur (16).

The reactivity of the oil varies depending on the concentration of the alkaline material, the type of alkaline material (silicate or hydroxide), the salinity of the water and the hardness of the water. Each of these variables should change in proportion to each other with time and with location within the reservoir (11). The water residing in the reservoir will usually have more hardness than the softened injection water which contains alkaline material. As the alkaline material contacts hardness, it makes the contacted water softer by a precipitation reaction which consumes the alkaline. As the water becomes softer, it tends to dissolve more salts, increasing its salinity, which in turn alters the reactivity to oil.

The caustic also attacks sand grains and can produce sodium orthosilicate with extended contact time. There is an optimum saddle point of IFT as a function of alkali concentration, oil concentration, and salinity. Alteration in salinity, consumption of alkali and production of silicate may help, or hurt, production at that reservoir location at that point in time. The dissolution of silicate from the sand can alter the wettability from oil wet to water wet, and back again, which can then allow more oil to be released into the water courses.

The precipitation reaction between alkaline flood water and resident water hardness ions is the same reaction used to soften the flood water on the surface. At a high pH, bicarbonate (HCO_3^-) is stripped of the hydrogen, forming carbonate ($CO_3^=$). The carbonate reacts very quickly to form calcium carbonate (Ca-CO_3) and magnesium carbonate (Mg-CO_3) which precipitate:

$$OH^- + HCO_3^- \rightleftharpoons H_2O + CO_3^=$$

$$Mg^{++} + CO_3^= \rightarrow MgCO_3 \downarrow$$

$$Ca^{++} + CO_3^= \rightarrow CaCO_3 \downarrow$$

By precipitating the magnesium and calcium from solution, the water becomes "softer." The desire for softened water is that sodium soap generates a more favorable IFT activity than does calcium soap and the reaction between alkaline and organic acids favors forming calcium soap over forming sodium soap.

As the oil reacts with alkaline, the oil's chemical composition changes. Excessive reactions can cause the oil to become "chemically burned." Some burned oils have a tendency to become very sticky and form immobile emulsions

(8) or produce emulsions which are hard to treat to saleable oil. The presence of sodium orthosilicate buffers the solution and reduces the tendency to burn. The cation exchange capacity of sodium orthosilicate is slightly different from that of sodium hydroxide, and the two chemicals separate by chromatographic lag at different rates under the influence of different reservoir material.

A reservoir-size core flood would be required to determine chromatographic separation, immobile emulsification reactions, in-situ production of sodium orthosilicate, caustic consumption by the rock and steady-state hardness because size and chemical-reaction scaling-factors have not been worked out. Small-scale core floods can give rough approximations of unburned oil production and arrival times. Caustic consumption is sometimes determined by crushing a rock sample and mixing with caustic and measuring remaining caustic at various points in time. These are the best tests currently availale and yield data of marginal use.

Testing for suitability to alkaline flood can be determined by:

1. Detailed IFT studies, examining the effect at various salinities, hardness, caustic concentrations and oil concentrations.

2. Detailed water study to determine fluctuations in water quality.

3. Log and core analysis for reservoir continuity determination and tertiary target volume.

4. Berea flood (optional) to determine displacement at minimum IFT.

5. Reservoir rock floods are not needed. One purpose of reservoir core floods is to determine consumption of alkali, and this is not a practical test (17).

SECTION III

SURFACE FACILITIES DESIGN

The water to be injected into the nine injection wells is produced water from Tract 25 battery, which is located in the northeast corner of Unit E. Tract 25 serves only Unit E producing wells and injection wells. The produced water is separated from the oil in a free-water knockout and transferred to a 1,000-bbl holding tank prior to being released to a pit system for reinjection into Unit E. The water is warm (110° F, which is reservoir temperature) and fairly clean. It has approximately 44 parts per million total hardness as Calcium Carbonate, some sulfide bacteria colonies, some residual oil and grease and some suspended fines. (The grease is an oil mass which sinks in the free-water tank.)

This produced water should be sieved to remove the grease balls and then chemically softened by the injection of sufficient Sodium Hydroxide to create an environment of pH = 10. At this pH, in a system closed to atmospheric carbon dioxide, the Bi-Carbonate Hydrogen is stripped off allowing the carbonate to react with the calcium and magnesium hardness ions to form Calcium Carbonate and Magnesium Carbonate precipitate (24,25). The bacterial colonies and suspended fines can act as nucleating sites to assist in achieving precipitation. Removal of the precipitate removes calcium and magnesium from the system which makes the water softer.

The precipitate grows with time and forms a floc as the solution ages. If the floc is not removed at a specific age (approximately 15 minutes to 6 hours, depending on the hardness), the floc becomes unstable and bursts into small fragments. These fragments are very fine and are difficult to remove. They in turn act as nucleating sites. At a pH greater than 10.4, the floc particles tend to repel other floc particles and cling to vessel surfaces, forming a scale. At pH 10 $\pm$ 0.2, the floc tends to coagulate to other floc particles and precipitate quickly.

The system was designed to run at a pH 10 and allow the floc to age in a reaction tank for routine blowdowns to the pit. Dilution of the blowdown reduces the pH and makes the precipitate less stable. Atmospheric carbon-dioxide should absorb into the pit water, decreasing the pH and should dissolve the precipitate.

The water decanted from the reaction tank should then be filtered to remove the floc remaining in suspension. The equilibrium hardness after filtration is 33 ppm and has been achieved in a full-scale softening test.

Addition of sodium silicate polishes the hardness to less than 1 ppm of magnesium and 3 ppm of calcium.

Finally, the water should be spiked with a second dose of sodium hydroxide and the resultant mixture re-filtered. This is the 2% caustic flood water for injection into the injection wells.

The injected water should be distributed to the injection wells based on zonal pore volume and injectivity on a well-by-well basis. The production wells have drawn the CFE area reservoir pressure down to approximately 200 psi and the adjoining acreage is at a reservoir pressure of 2000 psi (Figure 3). Confinement of alkaline flood chemicals to the CFE area should be accomplished by maintaining a pumped-off condition at the producers and adding edge injectors for hydraulic support.

SECTION IV

EQUIPMENT

A caustic flood requires only very basic items--soft water to reduce competitive reactions, chemical storage and blending equipment and an injection system to flush the chemical slug into the injection wells. In Unit E, no special provisions are made to selectively inject the chemical into zonal perforations or to gather and treat the tertiary production separately from the secondary production. A tight emulsion that would require additional test treaters is not anticipated, nor such large volumes that would require additional free-water knockouts, treaters, and storage equipment. Those may be required at some time in the future, but the historical performance of caustic floods by other operators and of the micellar project preflush in Unit A (4) indicates that the existing conventional production, flowlines and battery are adequate.

Figure 5, General Process Flow Diagram, displays the overall material balance. Notice that most of the flow equipment consists of conventional oil field items and are currently in operation at Unit E. The new material is a conventional waterflood pump and a chemical blending skid. Figure 6, Process Flow Diagram, indicates the simplicity of the blending and spiking set up. Figure 7--Plant Lay-out Tract 25-- shows the minimal acreage required. Figure 8 is a detailed drawing of the Chemical Blending Skid for a low-pressure design. A high-pressure blending skid was considered for immediate re-use on any injection line in the field. It was more practical to finalize the design for low-pressure use and to prove out the process. Modifications will be required in the design of caustic flood slugs in other parts of the field (harder water may require more chemical, some oils may require brine spiking, some waters may require pre or post softening or filtering, etc.), requiring modifications to the skid (additional or resized chemical pumps, more or different filters, alternate flow meters, automatic process control, etc.).

The skid is designed around a drilling rig doghouse so that all equipment is enclosed and yet very portable. The future design modifications should be easy to accommodate.

Figure 5 reflects a design to unload Highway transport trucks containing concentrated chemical directly into Unit E stock tanks. Concentrated material will coagulate when allowed to cool to 50° F and would have to be kept in heated, stirred and insulated tanks if to be used in a concentrated form. Dilution to one half of original concentrations (20-25% active after dilution) will lower the freezing point to between -15° F to -5° F, and will not need to be insulated. The dilution concentration can easily be checked with a hydrometer with a specific gravity range of 1.20 to 1.30 (20% = 1.223, 25% = 1.278). Dilution of 50% NaOH with 80° F water will result in 140° F maximum solution temperature due to the exothermic dilution reaction. This reaction can also be used to warm the stock tanks as needed. A blending pump is mounted on the blend skid to transfer concentrate to the day tanks via a strainer/filter. This will insure clean material for more precise metering into the final spiking line.

The production forecast is based on injection and production from specific zones. The zonal injection should balance the wells injection by zonal ØH. The well-to-well balance can be established originally by calculating relative pore volumes, but the wells actual injectivity will dominate the pattern balance shortly after startup.

SECTION V

CAUSTIC FLOOD ECONOMICS

There are four major components of the caustic flood proposal--(1) converting nine wells to water injection, (2) drilling four producing wells, (3) installing a water injection plant and (4) installing caustic blending equipment plus chemicals.

Pore Volume Analysis

Each proposed injection well was correlated to the central producer and average properties of each well and well pair were calculated, resulting in 32 reservoir segments.

The original oil-in-place (OOIP) for each reservoir segment was then calculated and cumulative production allocated to each segment was compared to the OOIP to calculate a zonal recovery factor. The additional oil from each zone was estimated, based on the recovery to date, for both increased waterflood and caustic flood (Tables 1-10).

Decline Curve Analysis

The CFE area wells produced 677,642 BO before unitization in January 1971, and have a cumulative production of 1,228,587 BO as of May 1981. Figure 11 is the production curve of all wells in Unit E; Figure 12 is the decline curve of CFE project wells only.

The advance of the line drive has been seen from the response of each row of producers. This response is plotted on Figure 13, CFE Project Wells Decline Curve Development. Notice that the same rate of decline has been applied to all three line drive rows and is consistent with the entire unit's history (Figure 12). The reserves on the Production Schedule from line drive and infill drilling are based on these decline rates. The Waterflood and Caustic Flood Prediction Curves (Figure 14) were developed into the production schedule by applying the line drive decline rates to the Zonal Volume Production Predictions. The decline rate was determined to be 0.025/MO with a hyperbolic N-factor of 0.38.

Statutory Cases

The Department of Energy requires that at least 500 ppm/PV be injected to be certified as a statutory tertiary flood. Certification improves the economics in three ways--first, a percentage of certain costs can be recouped under tertiary incentive front-end allowances; second, tertiary oil is taxed at a 30% windfall profits tax rate and secondary oil is taxed at 50%; third, all oil produced at a rate greater than a legislated decline rate is considered tertiary oil, and not just the volume of oil displaced by the activity of the injected chemical.

The minimum volume of chemical which must be injected into the pattern is 1565 Bbls (500 ppm). The volume of chemical which needs to be injected into the wells to achieve the pattern volume is 3155 Bbls. This is the "statutory minimum caustic flood." The oil volume recovered under the statutory minimum is assumed to be, for economic purposes, the same as the oil recovered using a technical maximum injection volume.

Case Analysis

Eight economic cases were evaluated:

Case 1. Production of 35 MBO at secondary oil prices. The project area would be abandoned as uneconomic in mid-1985. This condition was changed by the infill drilling program.

Case 2. Infill drilling results--production of 83 MBO. This case is the current condition, having spent $907 M for infill drilling and well conversion but no water injection. The incremental production of 48 MBO does not payout the investment.

Case 3. Waterflood only. This is proposed at a cost of $1.150 MM to obtain 342 MBO. The increment above infill alone is 259 MBO. The total economics are favorable with a profit before taxes of $4 MM and a payout in 1.1 years. The cost of infill drilling is applied in 1981 and the cost of the injection plant is applied in 1982.

Case 4. Caustic flood. This case assumes all production is at tertiary oil prices (30% WPT). It does not account for recoupment monies. The total production is 435 MBO, 93 MBO is tertiary and 342 MBO is from waterflood. Economics are favorable with 0.8 year payout and $6.5 MM cumulative cash flow BFIT.

Case 5. <u>Statutory caustic flood</u>. This case does not account for reduced efficiency of caustic performance by reducing the chemical slug from 12,000 Bbls to 3000 Bbls. It does not take credit for recoupment monies. Economics are artificially high.

Case 6. <u>Statutory decline</u>. This case arrives at the value of oil produced by the legislated decline rate (1%/mo since October 78--March 79 base period average of 1193 BOPM until start of chemical injection (March 1982) then 2-1/2%/mo). The total production of 130,200 BO is secondary oil.

Case 7. Incremental production. This is the difference between gross production of 435 MBO and the statutory prediction of 130.2 MBO. All oil is considered tertiary.

Case 8. This is the recommended case--Full Caustic Flood Production of 435 MBO; 130 MBO is legislated secondary; 305 MBO is legislated tertiary oil; recoupment is taken in 1981 and a total of $2 MM is spent to obtain $6.154 MM after expenses; payout is achieved in 0.8 year.

The details of cash flow and tax treatment have not been included to respect the wishes for privacy of the operating company.

SECTION VI

STATUTORY REQUIREMENTS

There are at least three governmental agencies directly involved with the initiation of the project. The Environmental and Geological agencies may become involved after initiation.

DOE

The U. S. Department of Energy, Economic Regulatory Administration was notified by the filing of OMB Form 38-R0445 (Self-Certification Initial Report) on February 17, 1981 of the intention to initiate an alkaline flooding project in Unit E. This filing has allowed certain drilling expenses to be recouped by the release of oil from controlled price to market price on the behalf of most working interest owners.

Montana Conservation Commission

The Conservation Commission has accepted the Secondary Operator's Agreement formed on unitization (1972) of Unit E. They must approve of plans for injecting chemicals into the subsurface formations of Montana.

IRS

The Internal Revenue Service becomes involved in tertiary projects through a reduction in Windfall Profits Tax from 50% for secondary oil to 30% for tertiary oil.

The DOE regulations allow an operator to certify a project by Designation of Agency, IRS ruling or Certification by Petroleum Engineer.

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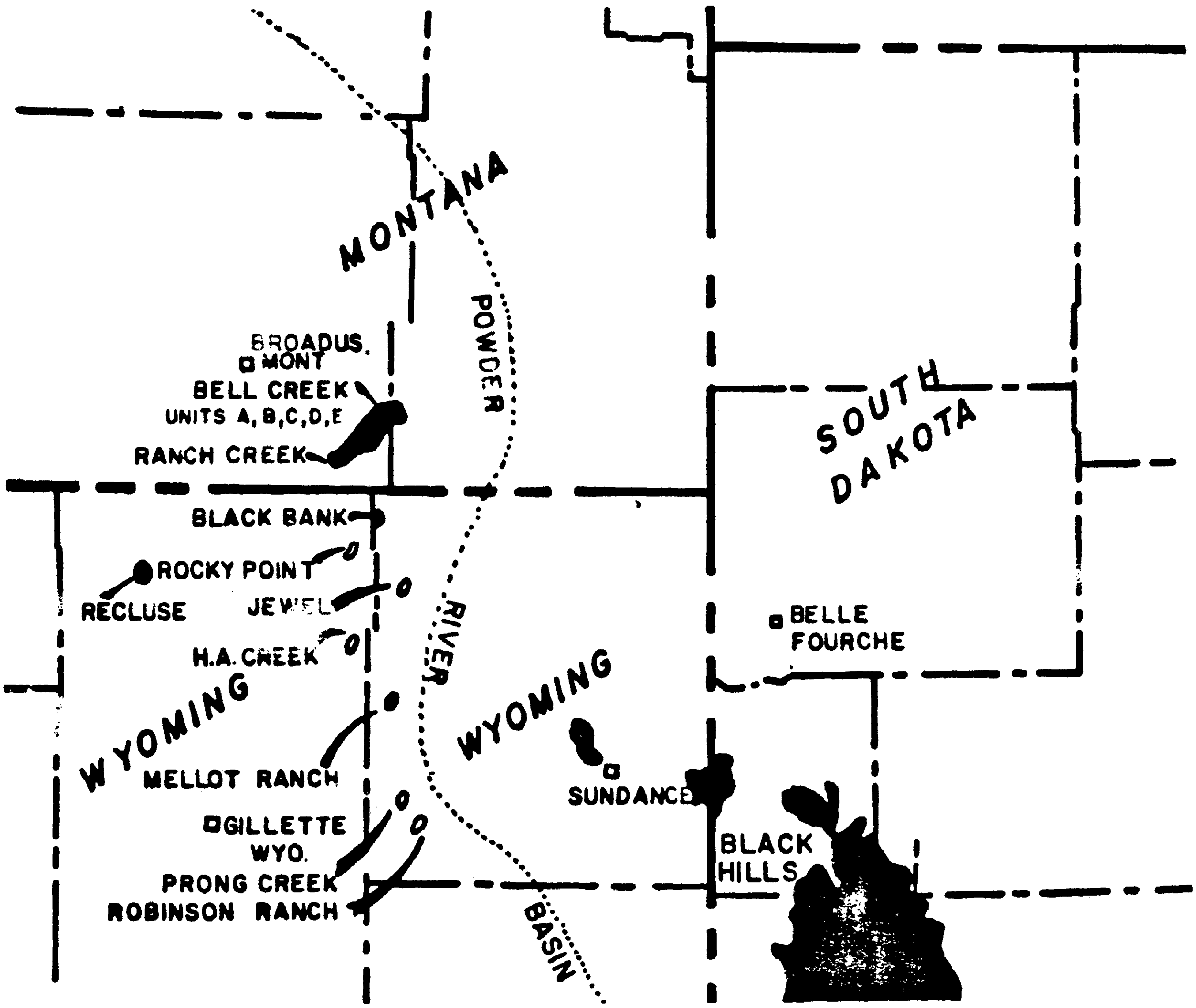
LIST OF FIGURES



LOCATION OF BELL CREEK FIELD
POWDER RIVER COUNTY, MONTANA

FIGURE 1

BELL CREEK FIELD
UNIT "A"
TYPE LOG
MUDDY INFORMATION

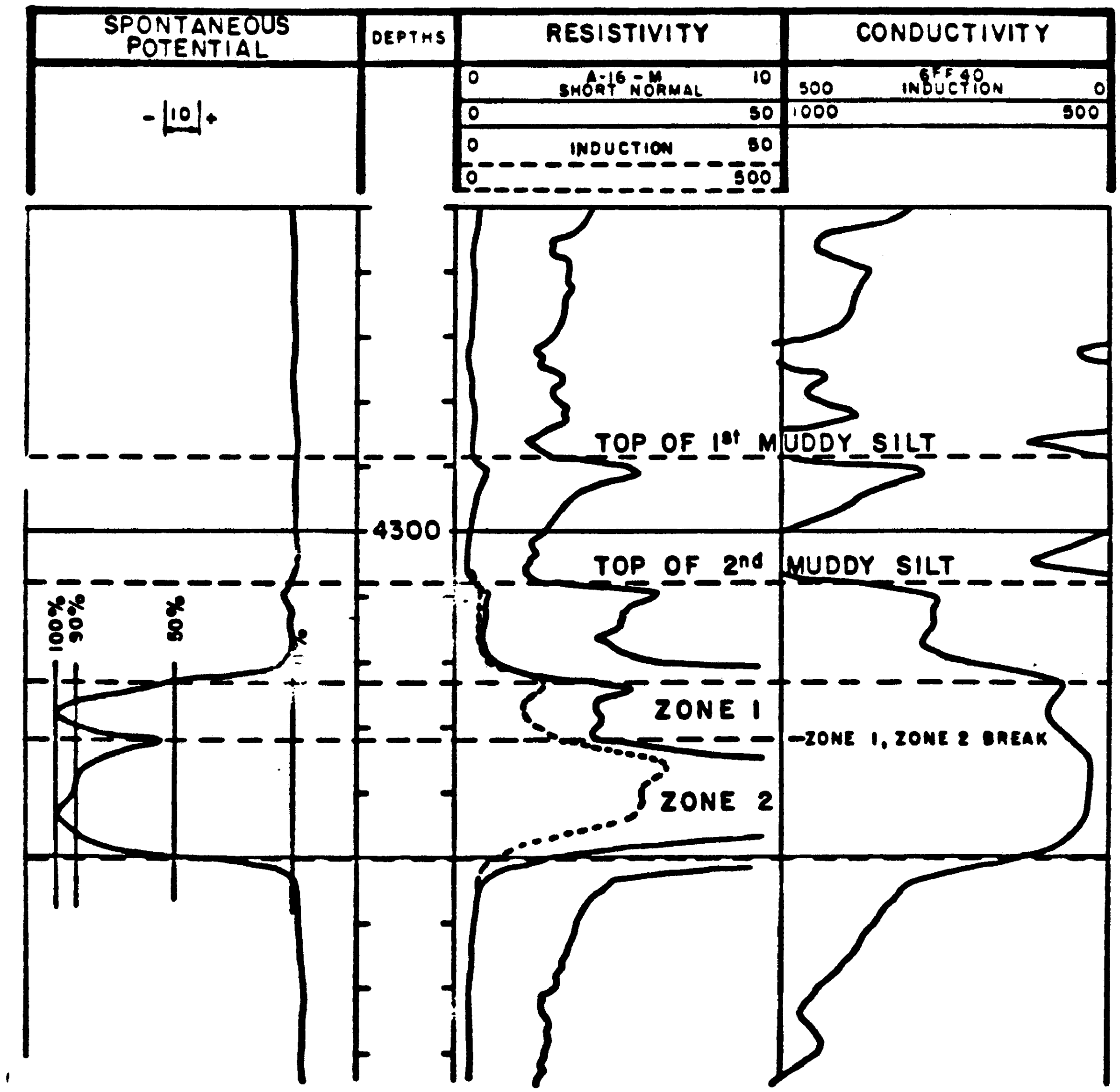
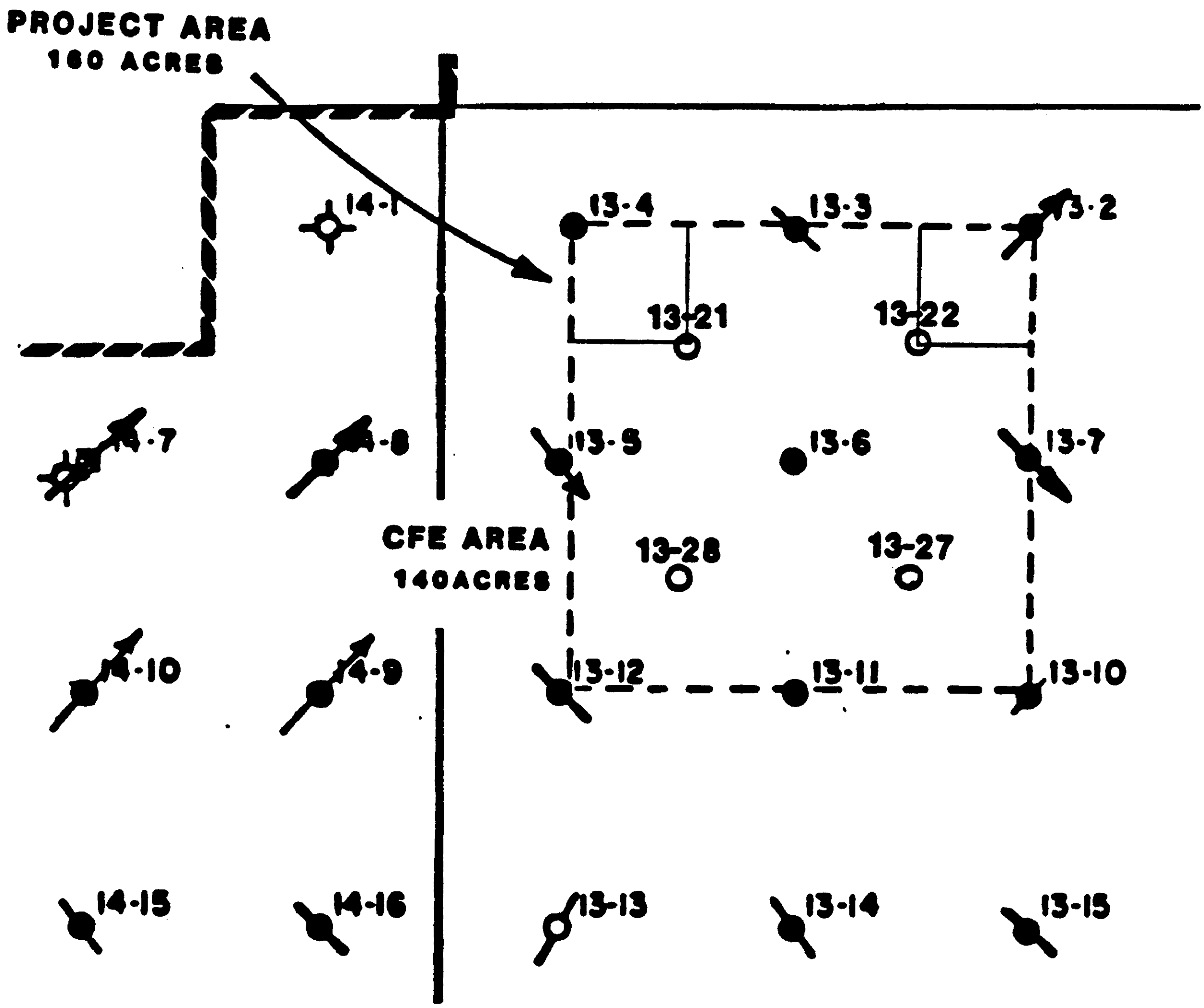
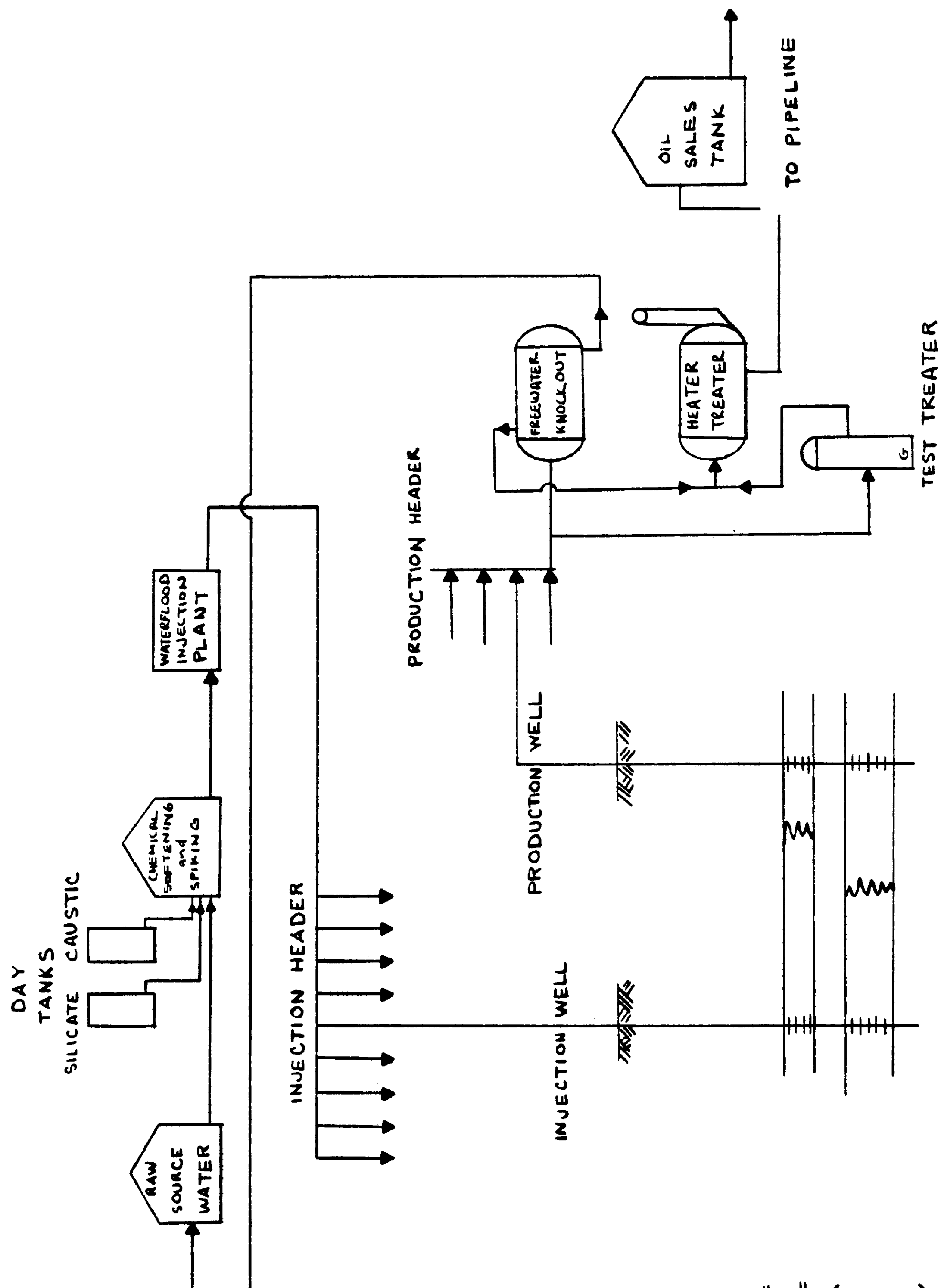


FIGURE 2

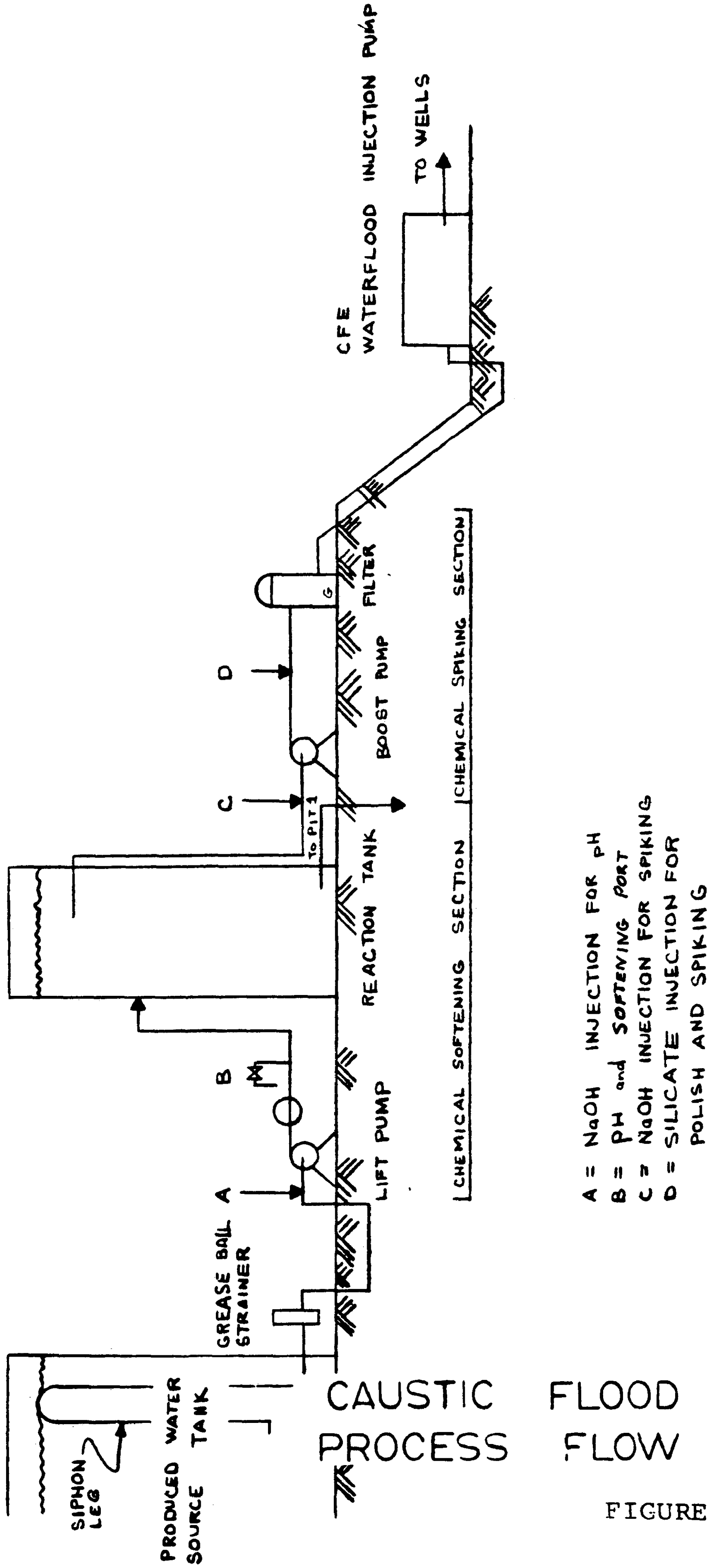


BELL CREEK FIELD
MUDDY SAND UNIT "E"
CAUSTIC FLOOD UNIT "E" (CFE)

FIGURE 3

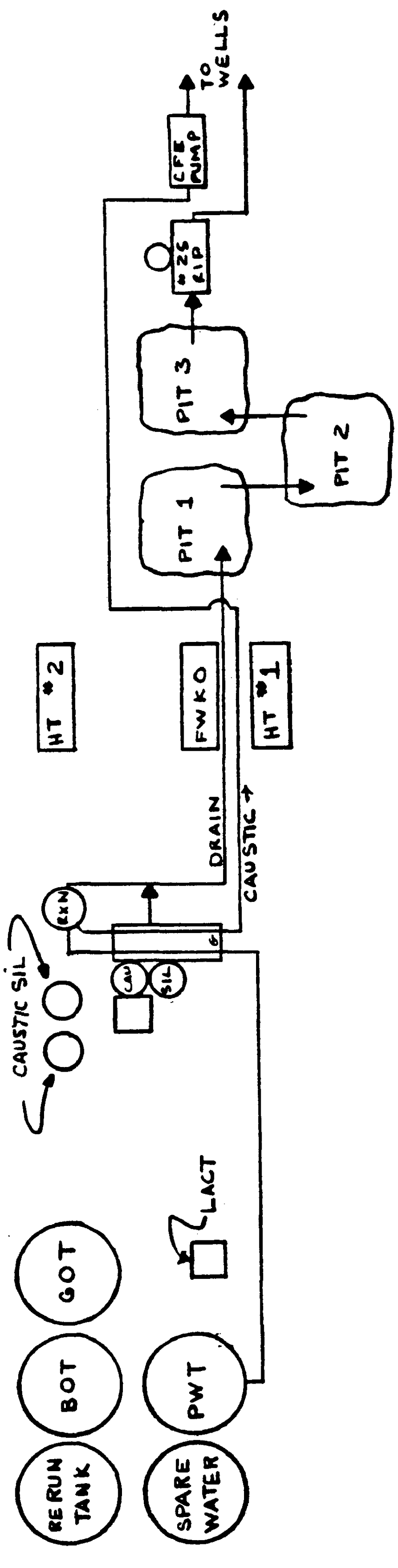


CAUSTIC FLOOD UNIT "E" (CFE)
PROCESS FLOW DIAGRAM-GENERAL
FIGURE 5



CAUSTIC FLOOD UNIT "E"
PROCESS FLOW DIAGRAM

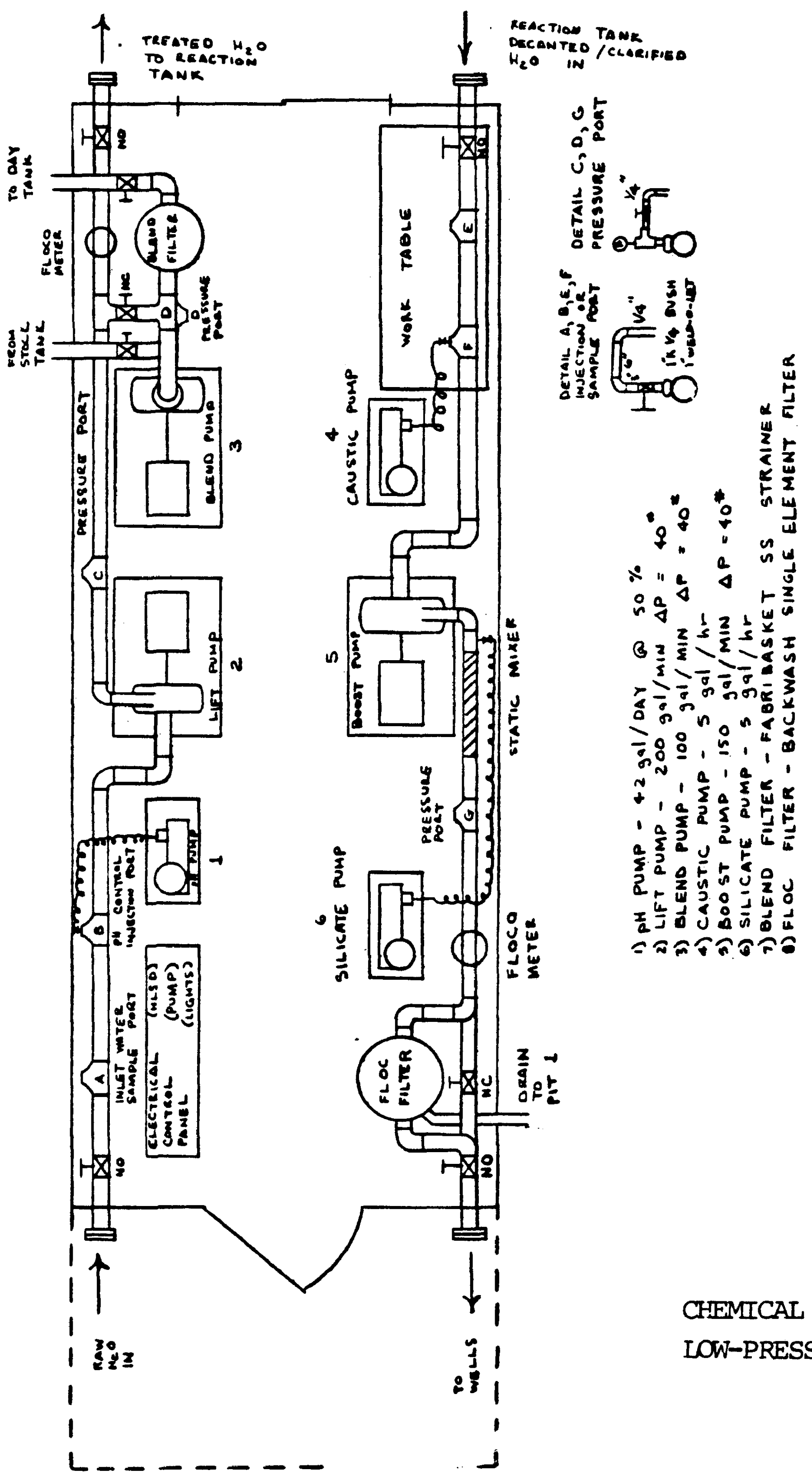
FIGURE 6



LEGEND:
BOT= BAD OIL TANK
GOT= GOOD OIL TANK
PWT= PRODUCED WATER TANK
LACT= LEASE AUTOMATIC CUSTODY TRANSFER PUMP
CAU= CAUSTIC SODA (NaOH) TANK
SIL= SODIUM METASILICATE TANK
RXN= REACTION TANK
FWKO= FREE WATER KNOCK OUT VESSEL
HT= HEATER-TREATER VESSEL
RIP= REINJECTION WATERFLOOD PLANT
CFE= CAUSTIC FLOOD UNIT E INJECTION PLANT

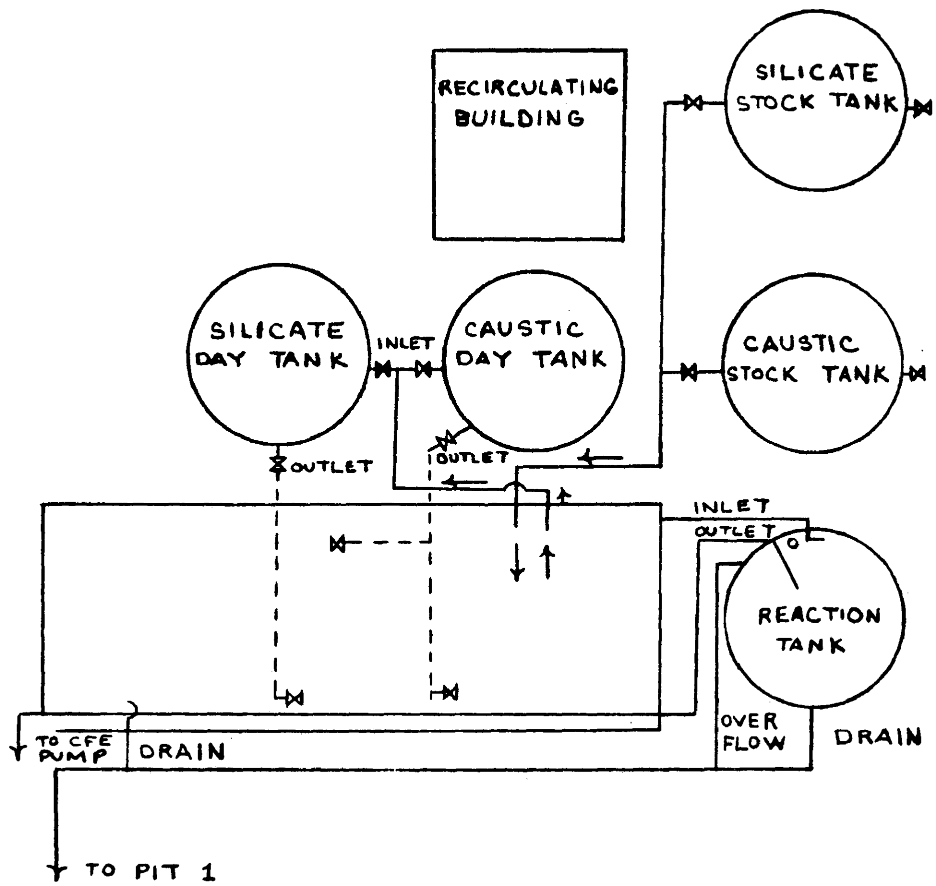
CAUSTIC FLOOD UNIT "E"
PLANT LAYOUT

FIGURE 7



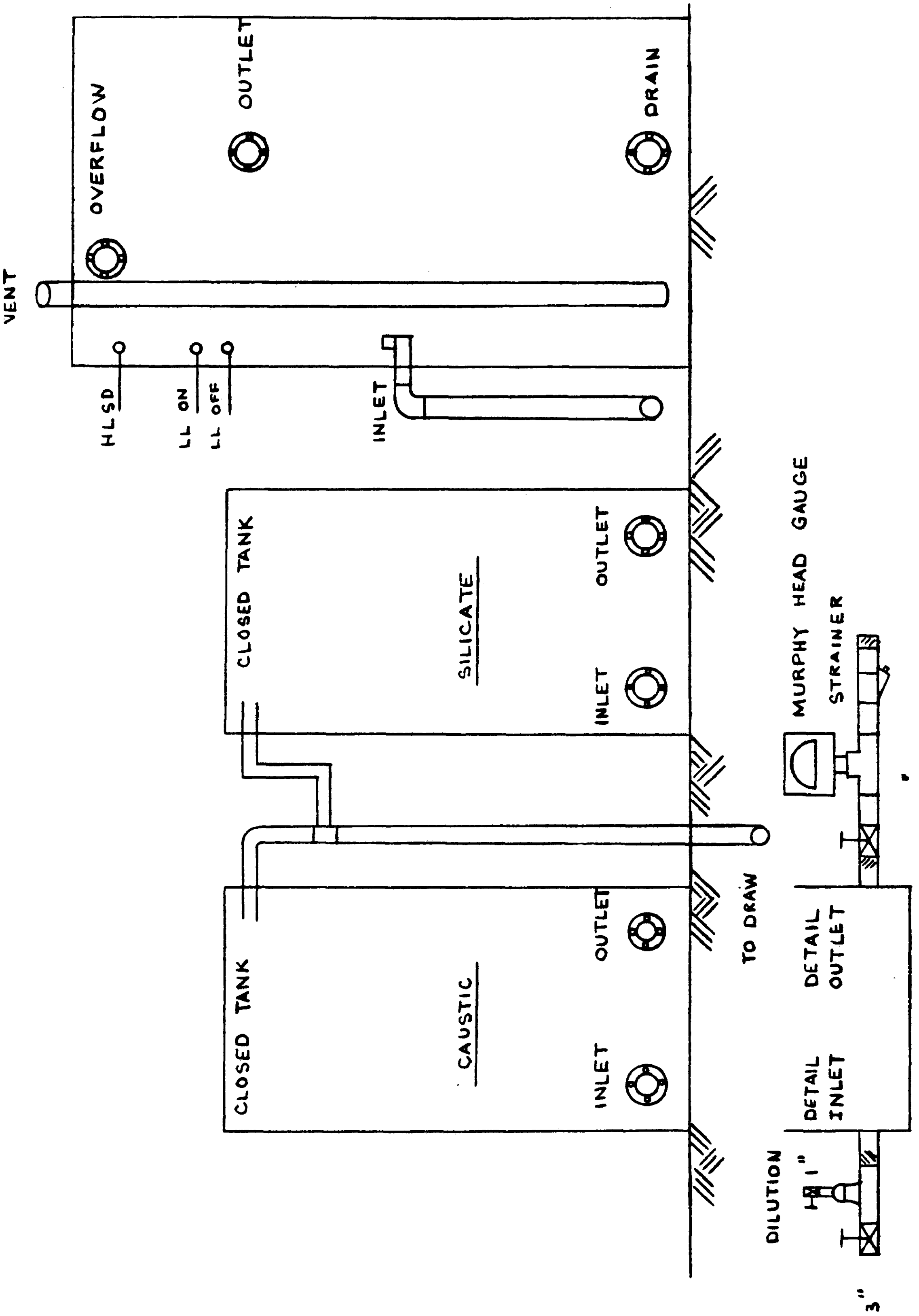
CHEMICAL BLENDING SKID
LOW-PRESSURE DESIGN

FIGURE 8



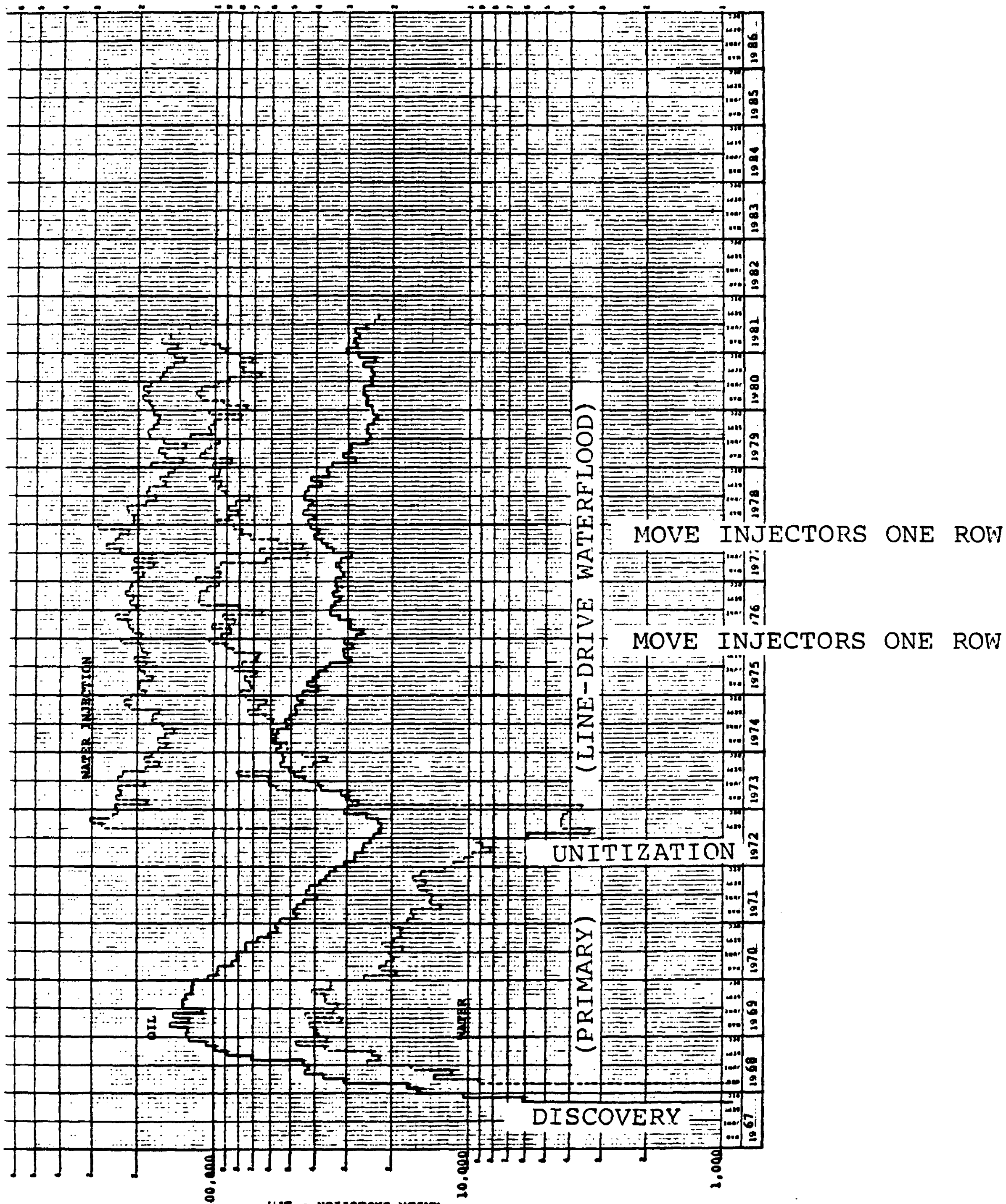
CFE TANKAGE - FLOWLINES

FIGURE 9



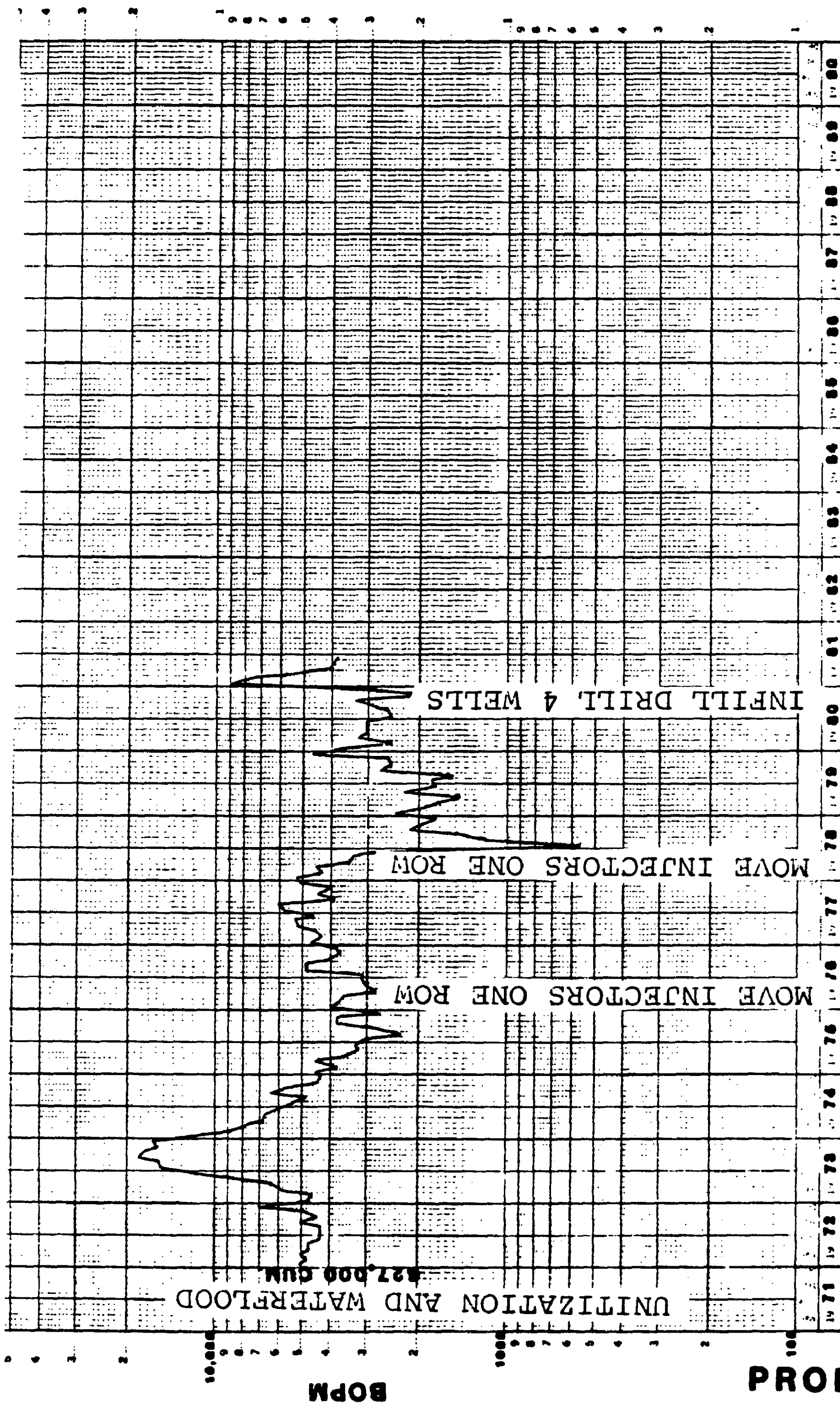
TANKAGE - FITTINGS

FIGURE 10



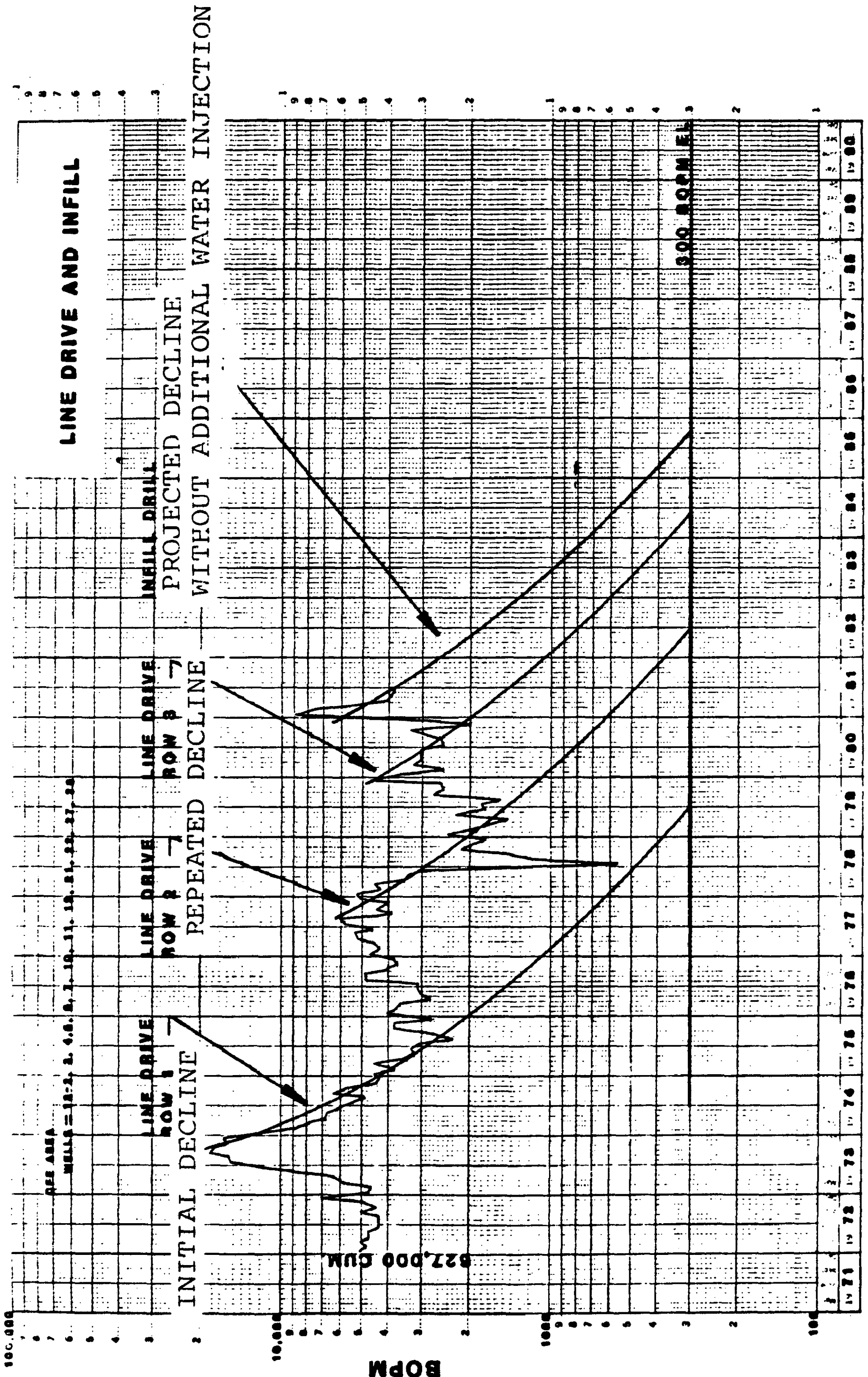
PRODUCTION CURVE
UNIT E (ALL WELLS)

FIGURE 11



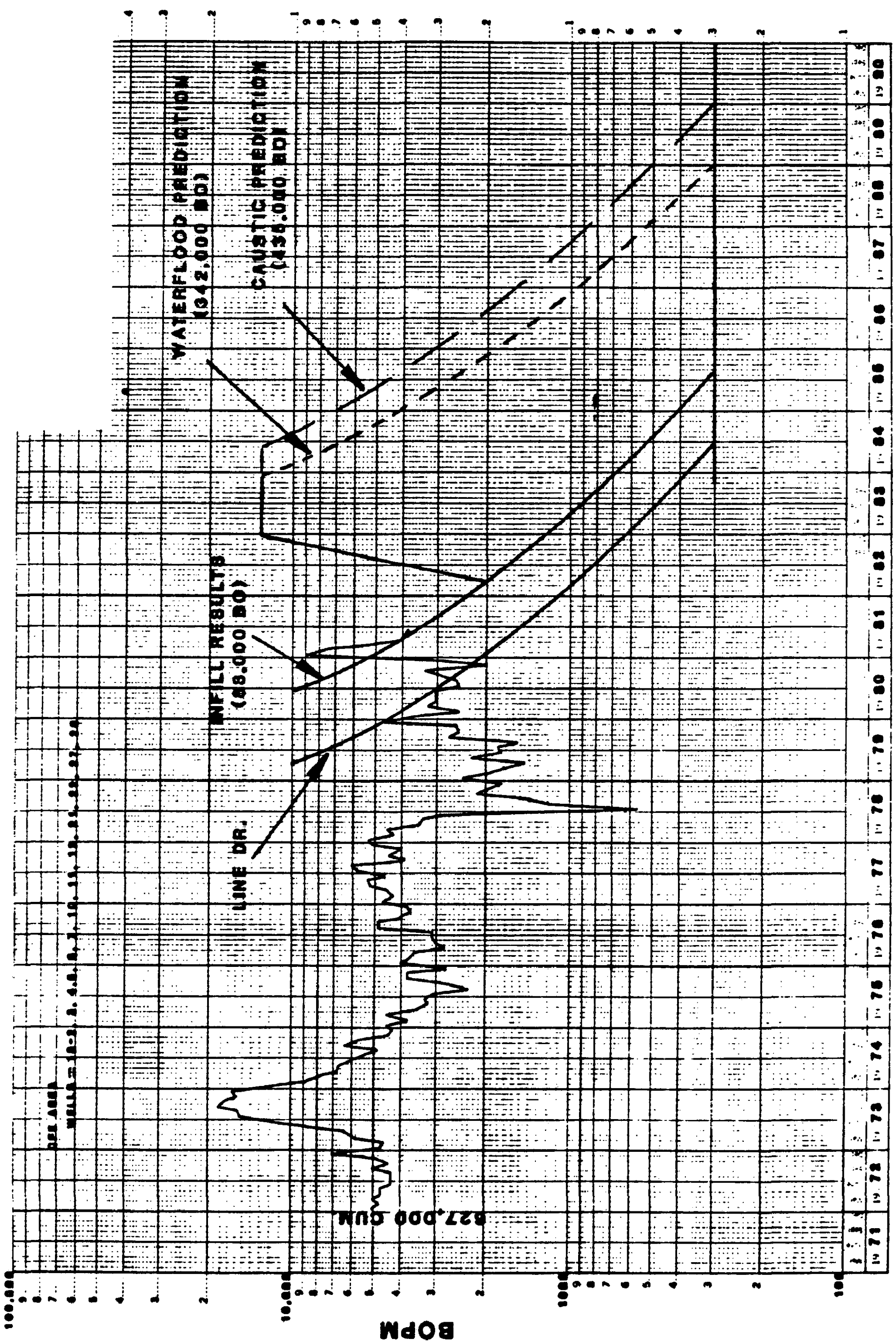
PRODUCTION CURVE
CFE PROJECT WELLS

FIGURE 12



CFE PROJECT WELLS
DECLINE CURVE DEVELOPMENT

FIGURE 13



CFE WATERFLOOD and CAUSTIC FLOOD PREDICTION CURVES

FIGURE 14

LIST OF TABLES

Table 1

INDIVIDUAL ZONAL VOLUMES

UPPER ZONE

Well	13-22	13-2	13-3	13-6	13-7	Ave
Gross H	8	4	16	12	8	9.6
Net H at ϕ	8@21	4@20	14@26	12@12	4@22	8.4 = H
ϕH	1.68	0.8	3.64	1.44	0.88	
ϕH_{ave}		1.24	2.66	1.56	1.28	1.69 ϕH
						.20 ϕ

	13-21	13-4	13-3	13-6	13-5	
GH	11	18	16	12	11	13.6
NH@ϕ	4@20	13@24*	14@26	12@12	6@18	+ 4@21 = 10@19
ϕH	0.80	3.12	3.64	1.44	1.92	9.2 = H
ϕH_{ave}		1.12	2.22	1.12	1.36	1.46 = ϕH_a
		6' perf:,ϕH = 1.44				.16 ϕ

	13-27	13-10	13-11	13-6	13-7	
GH	11	12	10	12	8	10.6
NH@ϕ	8@12	6@18	7@20	12@12	4@22	7.4 = H
ϕH	.96	1.08	1.40	1.44	.88	
ϕH_{ave}		1.02	1.18	1.70	0.92	1.21 = ϕH
						.16 = ϕ

	13-28	13-12	13-11	13-6	13-5	
GH	12	14	10	12	11	11.8
NH@ϕ	7@20.5	7@17	7@20	12@12	6@18	+ 4@21 8.6 = H
ϕH	1.44	1.19	1.40	1.44	1.92	
ϕ		1.32	1.42	1.44	1.68	1.47 = ϕH
						0.17 = ϕ

Gross H_{ave} = 11.4

Net H_{ave} = 8.4

Net ϕH_{ave} = 1.458

ϕ_{ave} = 17.4

Table 2

ZONAL VOLUMES

LOWER ZONE

	13-22	13-2	13-3*	13-6	13-7*	Ave
GH	12	30	8	10	12	14.4
NH@ϕ	4@19	15@20	7@19	7@18	6@21 + 4@25	6.2@.18
		(8' Perf)	(2' Perf)			
ϕH	.76	3.0 (1.6)	1.33 (.38)	1.26	2.26	
ϕH_{ave}		1.18	0.57	1.01	1.51	1.13

	13-21*	13-4	13-3*	13-6	13-5	
GH	6	4	8	10	27	11.0
NH@ϕ	6@23	2@17	7@19	7@18	22@22	7.4@16
ϕH	1.38	0.0	1.33	1.20	4.80	
ϕH_{ave}		(none perf)	0.88	1.32	3.09	1.20
			2' perf:.38			

	13-27	13-10	13-11	13-6	13-7*	
GH	16	12	11	10	12	12.2
NH@ϕ	9@13	6@18	6@22	7@18	10@22.5	7.6@18
ϕH	1.17	1.08	1.32	1.26	2.26	
ϕH_{ave}		1.13	1.25	1.22	1.72	1.33

	13-28	13-12	13-11	13-6	13-5	
GH	10	10	11	10	27	13.6
NH@ϕ	5@20	5@17	6@22	7@18	22@23	9@17
ϕH	1.0	.85	1.32	1.26	5.06	
ϕH_{ave}		0.93	1.16	1.13	3.03	1.56

*13-3 has a basal zone with 4'@23%
*13-7 has a basal zone with 4'@22
*13-21 has a basal zone with 6'@26

Gross H_{ave} = 12.8

Net H_{ave} = 7.5

Net ϕH_{ave} = 1.305

ϕ_{ave} = 17.3%

Table 3

PATTERN PORE VOLUMES, WELLS 13-22 AND 13-21

		13-22	13-2	13-3	13-6	13-7	Total
ϕH	U FT	1.68	0.80	3.64	1.44	0.88	
ϕH	L FT	0.76	1.60	0.38	1.26	2.26	
ϕH_{ave}	U FT	-	1.24	2.66	1.56	1.28	
ϕH_{ave}	L FT	-	1.18	0.57	1.01	1.51	
P.V.	U BBLS	-	96,199	206,362	121,024	99,302	523,200
P.V.	L BBLS	-	91,544	44,220	78,355	117,145	331,200
OOIP	U BBLS	-	72,400	155,400	91,000	77,800	396,600
OOIP	L BBLS	-	68,900	33,300	59,000	88,200	249,400
OOIP	T BBLS	-	141,300	188,700	150,000	166,000	646,000
Project Allocation Factor							
Project		-	1/4	1/2	1/1	1/2	
Zone U		-	0.330	0.910	0.530	0.280	
Zone L		-	0.770	0.090	0.470	0.720	
Pattern		-	1.000	0.490	0.270	0.510	
Factor U		-	0.058	0.223	0.143	0.063	
Factor L		-	0.193	0.022	0.127	0.162	
Factor T		1.0	0.250	0.245	0.270	0.225	

		13-21	13-4	13-3	13-6	13-5	Total
ϕH	U FT	0.08	1.44	3.64	1.44	1.92	
ϕH	L FT	1.38	0.00	0.38	1.26	4.80	
ϕH_{ave}	U FT	-	1.12	2.22	1.12	1.36	
ϕH_{ave}	L FT	-	0.00	0.88	1.32	3.09	
P.V.	U BBLS	-	86,890	172,228	86,890	105,500	451,508
P.V.	L BBLS	-	0	68,270	102,405	239,700	410,375
OOIP	U BBLS	-	65,430	129,200	65,400	79,400	340,000
OOIP	L BBLS	-	0	51,400	77,100	180,500	309,000
OOIP	T BBLS	-	65,430	181,100	142,500	259,940	649,000
Project Allocation Factor							
Project		-	1/4	1/2	1/1	1/2	
Zone U		-	1.000	0.910	0.530	0.290	
Zone L		-	0.000	0.090	0.470	0.710	
Pattern		-	1.000	0.510	0.270	0.490	
Factor U		-	0.250	0.232	0.143	0.071	
Factor L		-	0.000	0.023	0.127	0.174	
Factor T		1.0	0.250	0.255	0.270	0.245	

Table 4

PATTERN PORE VOLUMES, WELLS 13-27 AND 13-28

		13-27	13-10	13-11	13-6	13-7	Total
ϕH	U FT	0.96	1.08	1.40	1.44	0.88	
ϕH	L FT	1.17	1.08	1.32	1.26	2.26	
ϕH_{ave}	U FT	-	1.02	1.18	1.20	0.92	
ϕH_{ave}	L FT	-	1.13	1.25	1.22	1.72	
P.V.	U BBLS	-	79,131	91,544	93,096	71,373	335,144
P.V.	L BBLS	-	87,665	96,975	94,647	133,437	412,724
OOIP	U BBLS	-	59,600	69,000	70,100	53,700	252,400
OOIP	L BBLS	-	66,000	73,000	71,300	100,500	310,800
OOIP	T BBLS	-	125,600	142,000	141,400	154,200	563,200

Project Allocation Factor	13-27	13-10	13-11	13-6	13-7
Project	-	1/4	1/2	1/1	1/2
Zone U	-	0.500	0.510	0.530	0.280
Zone L	-	0.500	0.490	0.470	0.720
Pattern	-	1.000	0.490	0.240	0.490
Factor U	-	0.125	0.125	0.113	0.069
Factor L	-	0.125	0.120	0.127	0.176
Factor T	1.0	0.250	0.245	0.240	0.245

		13-28	13-12	13-11	13-6	13-5	Total
ϕH	U FT	1.44	1.19	1.40	1.44	1.92	
ϕH	L FT	1.00	0.85	1.32	1.26	5.06	
ϕH_{ave}	U FT	-	1.32	1.42	1.44	1.68	
ϕH_{ave}	L FT	-	0.93	1.16	1.13	3.03	
P.V.	U BBLS	-	102,405	110,163	111,715	130,334	454,617
P.V.	L BBLS	-	72,150	89,992	87,665	235,067	484,847
OOIP	U BBLS	-	77,100	83,000	84,100	98,100	342,300
OOIP	L BBLS	-	54,300	67,700	66,000	177,000	365,000
OOIP	T BBLS	-	131,400	150,700	150,100	275,100	707,300

Project Allocation Factor	13-28	13-12	13-11	13-6	13-5
Project	-	1/4	1/2	1/1	1/2
Zone U	-	0.580	0.510	0.530	0.290
Zone L	-	0.420	0.490	0.470	0.710
Pattern	-	1.000	0.510	0.240	0.510
Factor U	-	0.145	0.125	0.113	0.181
Factor L	-	0.105	0.130	0.127	0.074
Factor T	1.0	0.250	0.255	0.240	0.255

Table 5

CFE AREA WELLS
CUMULATIVE PRODUCTION

Well	Pre-unitization	Thru May 1981		
	Barrels of Oil	Barrels of Oil	Barrels of Water Produced	Barrels of Water Injected
13-2	9	9	-	305,327
3	150,494	371,689	566,531	-
4	86,272	-	160,257	-
5	166,951	281,912	-	810,800
6	58,468	105,208	10,716	-
7	37,044	49,046	-	-
10	2,382	2,581	28,938	-
11	73,114	119,766	351,704	-
12	102,912	113,267	193,549	-
21	0	1,236	39,648	-
22	0	2,231	43,216	-
27	0	1,052	46,112	-
28	0	15,429	34,301	-
	677,642	1,228,587	1,479,972	1,116,127

Table 6
WELL 13-22 PATTERN
PRODUCTION PREDICTIONS

	13-22	13-2	13-3	13-6	13-7	TOTAL
CUM PROD	2321	9	371,689	105,208	49,046	
ALLOC P U	-	1	82,868	15,045	3,090	
L	-	1	8,196	13,361	7,945	
T	2321	2	91,064	28,406	11,035	133,800
% OOIP						
U	-	0	53.3	16.5	4.0	
L	-	0	24.6	22.6	9.0	
T	1.0	0	48.3	18.9	6.6	
ZONAL COND						
U	-	US-N	FS	US	US	
L	-	US-N	US	US	US	
ADD REC (% OOIP)						
WF-U	-	0	4	15	20	
WF-L	-	0	15	18	20	
CF-U	-	0	4	4	4	
CF-L	-	0	4	4	4	
ADD VOL(BO)						
WF-U	-	0	6,200	13,600	15,600	85,400
WF-L	-	0	5,000	10,600	17,600	33,200
CF-U	-	0	6,200	3,600	3,100	12,900
CF-L	-	0	1,300	2,400	3,500	7,200
TOTAL	-	0	18,700	30,200	39,800	88,700

RECOMMENDATION:
Do not inject caustic into 13-2

P.V. Contacted by caustic = 666,657 BPV (13-2 removed)

KEY: US = unswept - N = not sweepable
PS = partialy swept
FS = fully swept

Table 7

WELL 13-21 PATTERN PRODUCTION PREDICTIONS

		13-21	13-4	13-3	13-6	13-5	TOTAL
CUM PROD		1236	165,170	371,689	105,208	281,912	
ALLOC P	U	-	41,300	86,230	15,000	20,000	
	L	-	0	8,550	13,400	49,000	
	T	1236	411,300	94,780	28,400	69,000	213,480
% OOIP							
	U	-	63.0	66.5	22.9	25.1	
	L	-	-	16.6	17.4	27.2	
	T	-	63.0	55.4	19.9	26.5	
ZONAL COND							
	U	-	FS	FS	P-S	P-S	
	L	-	US	P-S	P-S	P-s	
ADD REC (% OOIP)							
	WF-U	-	0	4	17	15	
	WF-L	-	0	15	13	13	
	CF-U	-	4	4	4	4	
	CF-L	-	0	4	4	4	
ADD VOL(BO)							
	WF-U	-	0	5,200	11,000	12,000	28,200
	WF-L	-	0	7,700	10,000	23,400	41,100
	CF-U	-	0	5,200	2,600	3,000	10,800
	CF-L	-	0	2,000	3,000	7,200	12,200
	TOTAL	-	0	20,100	26,600	45,600	92,300

RECOMMENDATION:

Don't inject caustic 13-4, but do inject water

Pore volume subject to caustic: 624,495 (13-4 removed)

Table 8

WELL 13-27 PATTERN
PRODUCTION PREDICTIONS

	13-27	13-10	13-11	13-6	13-7	TOTAL
CUM PROD.	1052	2,581	119,766	105,282	49,046	
ALLOC P U	-	323	14,900	11,900	3,400	
L	-	322	14,400	13,400	8,600	
T	1052	645	29,300	25,300	12,000	68,300
% OOIP						
U	-	1	22	17	6	
L	-	1	20	19	9	
T		1	21	18	8	
ZONAL COND						
U	-	US	PS	PS	US	
L	-	US	PS	PS	US	
ADD REC (% OOIP)						
WF-U	-	20	18	13	20	
WF-L	-	20	10	11	20	
CF-U	-	4	4	4	4	
CF-L	-	4	4	4	4	
ADD VOL(BO)						
WF-U	-	12,000	12,400	9,100	10,800	44,300
WF-L	-	13,000	7,300	7,900	20,000	48,200
CF-U	-	2,400	2,800	2,800	2,100	10,100
CF-L	-	2,600	2,900	2,800	4,000	12,300
TOTAL	-	30,000	25,400	22,600	36,900	114,900

Pore volume subject to caustic: 747,481 BBLS.

Table 9

WELL 13-28 PATTERN
PRODUCTION PREDICTIONS

	13-28	13-12	13-11	13-6	13-5	TOTAL
CUM PROD	15,429	113,267	119,764	105,208	281,912	
ALLOC P U	-	16,400	15,000	11,900	51,000	
L	-	11,900	15,500	13,350	20,900	
T	15,429	28,300	30,500	25,250	71,900	171,400
% OOIP						
U	-	21.3	18.1	14.1	52.0	
L	-	21.9	22.9	20.2	11.8	
	-	21.5	20.3	16.8	26.1	
ZONAL COND						
U	-	PS	PS	PS	SP	
L	-	PS	PS	PS	PS	
ADD REC (% OOIP)						
WF-U	-	19	12	15	4	
WF-L	-	19	18	20	20	
CF-U	-	4	4	4	4	
CF-L	-	4	4	4	4	
ADD VOL(BO)						
WF-U	-	14,700	10,000	12,600	4,000	41,300
WF-L	-	10,300	12,000	13,200	35,500	71,000
CF-U	-	3,100	3,300	3,400	4,000	13,800
CF-L	-	2,200	2,700	2,600	7,000	14,500
TOTAL	-	30,300	28,000	31,800	50,500	140,600

Pore volume subject to caustic: 939,464 BBLS

Table 10

COMBINED PRODUCTION PREDICTIONS (BY PATTERN)

	13-22	13-21	13-27	13-28	TOTAL
WF U	35,400	28,200	44,300	41,300	149,200
WF L	33,200	41,100	48,200	71,000	193,500
T	68,600	69,300	92,500	112,300	342,700
CF U	12,900	10,800	10,100	13,800	47,600
CF L	7,200	12,200	12,300	14,500	46,200
T	20,100	23,000	22,400	27,300	93,800
TT	88,700	92,300	114,900	140,600	436,500

Pore Volume Enclosed in 160 Acres

U	523,200	451,500	335,000	455,000	1,764,500
L	331,200	410,400	413,000	485,000	1,639,600
	854,400	861,900	748,000	840,000	3,404,100

Pore Volume Contributing (140 acres)

U	427,000	365,000	335,000	455,000	1,582,000
L	240,000	410,000	413,000	485,000	1,548,000
	667,000	775,000	748,000	840,000	3,130,000

Caustic Requirements: Statutory

3,130,000 BPV * 500 PPM = 1565 BBLS Caustic injected into pattern

Basis: 500 BWI/DAY/WELL

Inj Wells	Factor
13-3	0.500
13-5	0.500
13-6	1.000
13-7	0.470
13-10	0.250
13-11	0.500
13-12	0.250
	3.47/7 = 0.496

Inject 3155 BBL caustic total to achieve 1565 Bbls in pattern.

Inject for 32 days to achieve statutory flood.

TABLE 11

RESERVOIR DATA SHEET

Formation:	Muddy Sand, Bell Creek Zones I, II and III (upper, lower, basal)
Depth:	4400' (795' Sub Sea)
Acres:	160 acres enclosed with 4 normal 5 spots 140 acres to be caustic flooded, with water injection in 20 acres
Avg. Gross Thickness:	24 feet (11 upper, 13 lower)
Avg. Net Pay:	16 feet (8 upper, 8 lower)
Avg. Porosity:	17.4% (17.4% upper, 17.3% lower)
Original Water Saturation:	24.7% (from unitization studies)
Pore Volume: (Reservoir Bbls)	3.40 MM Bbls (1.80 MM Bbls upper; 1.6 MM Bbls lower)--160 acres 3.13 MM Bbls (1.58 MM Bbls upper; 1.55 MM Bbls lower)--140 acres
Original Oil-in-Place (OOIP):	2.565 MM Bbls--160 acres (reservoir bbls) 2.359 MM Bbls--140 acres (reservoir bbls) 2.058 MM Bbls--140 acres (stock-tank bbls)
Cumulative Production: (Stock-Tank Bbls)	1,228,587 BO (6-81)--sold from all project wells 609,379 BO--(attributed to the 140 acres)
% OOIP:	29.6% of project
Remaining Reserves:	(6-81 to abandonment)
Line Drive Recovery:	35,340 BO (decline curve to 300 BOPM Economic Limit) This would

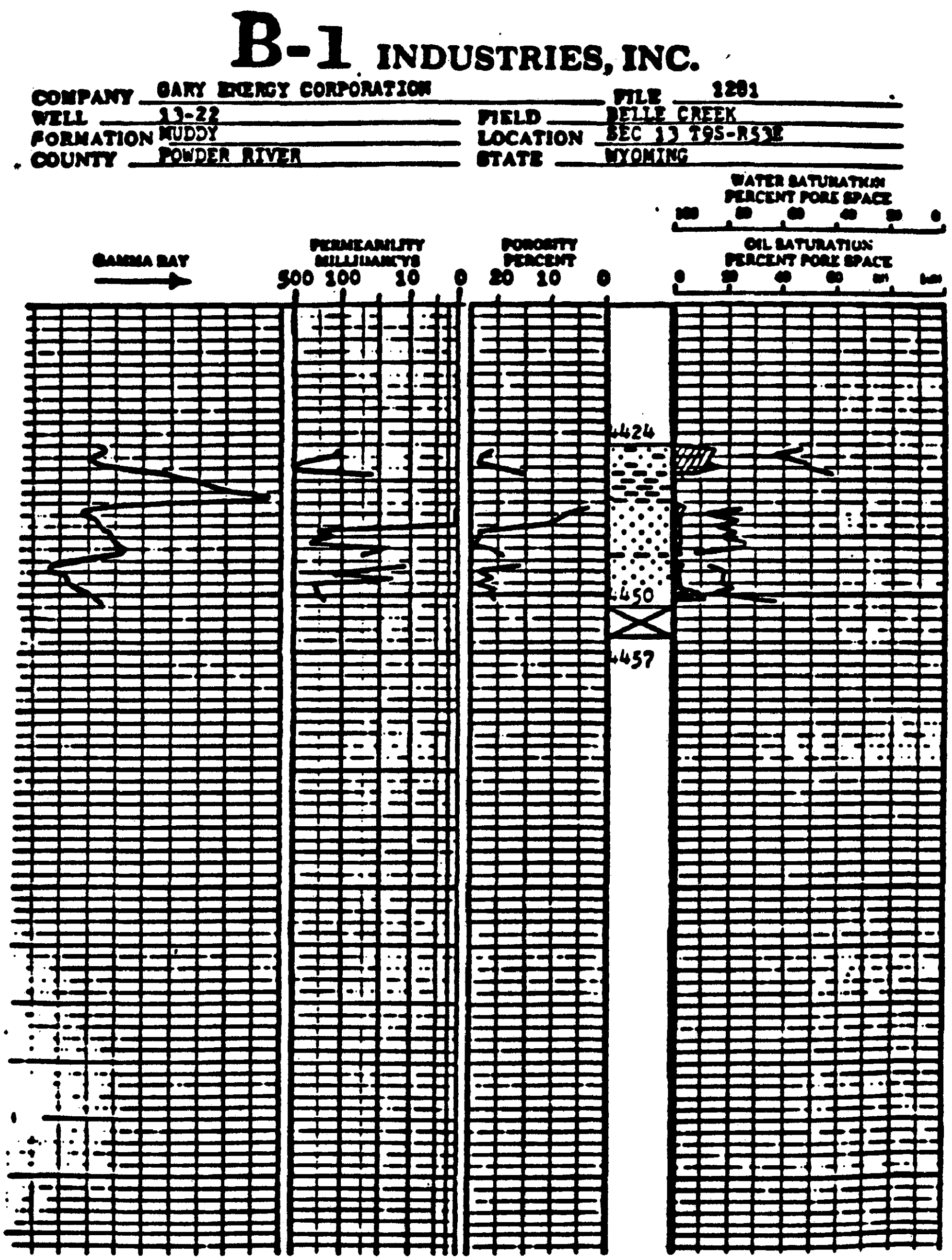
TABLE 11 (CONTINUED)

	have been the ultimate recovery had infill wells not been drilled)
Infill Drill Recovery:	83,090 BO (decline curve) (without additional injection)
Waterflood Recovery:	342,000 BO (Summation of Zonal Volumes) (assuming all connected lenses flood to individual waterflood residual)
Caustic Flood Recovery:	435,000 BO (Summation of Zonal Volumes) (lenses at or above waterflood residual release oil to waterflood residual, plus 4% of OOIP in that lense). Incremental Caustic Recovery is 93,000 BO.
Formation-Volume Factor:	1.146 at original bubble-point pressure of 1000 psig (A volume factor of 1.0 was used in predicting future recoveries. This should not be a significant variation from the actual [and unknown] volume factor determined at the current bubble-point of approximately 50 psig)
Reservoir Temperature:	110°F

ATTACHMENT III

APPENDICES

(APPENDIX 1, page 1 of 2)



(APPENDIX 1, page 2 of 2)

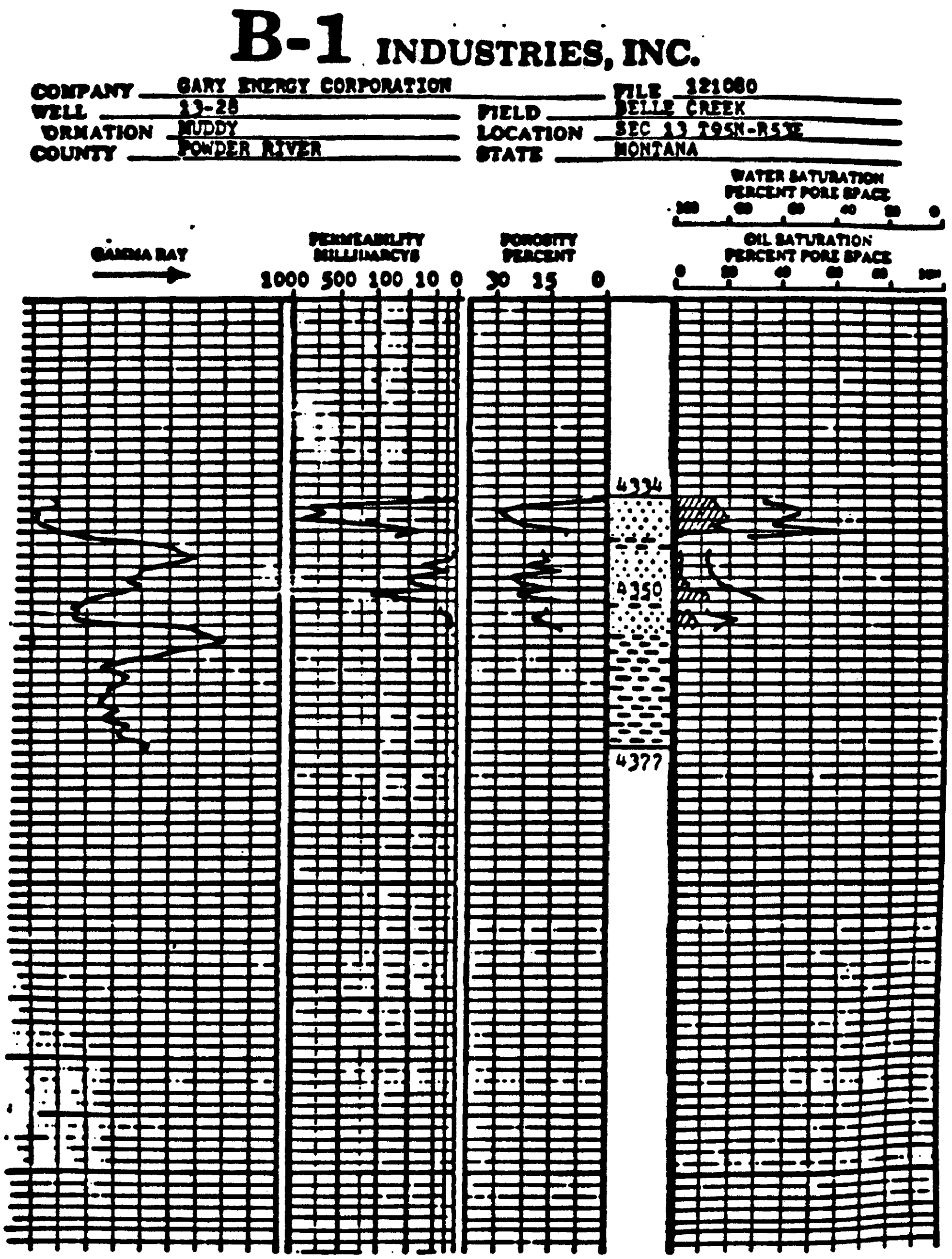
B-1 INDUSTRIES, INC.
CORE ANALYSIS REPORT

COMPANY GARY ENERGY CORPORATION FILE NO. 1281
WELL 13-22 Unit E' FORMATION MUDDY DATE 1-7-81
FIELD BELLE CREEK CORE TYPE DIA 3½" ELEVATION 3654
COUNTY POWDER RIVER MUD TYPE ANALYST BP DH LJ GP KB
STATE MONTANA LOCATION SEC 13 T9S-R53E

SAMP NO	DEPTH	PERMEABILITY HORIZ	PERMEABILITY VERT	POR %	OIL %	WATER %	GR DNS	DESCRIPTION
1	4424-25	130		21.2	14.9	54.2	2.60	SS GY VFG SHY
2	-26	141		23.5	12.7	63.4	2.61	SS GY VFG SHY
3	-27	428		24.2	12.1	51.6	2.60	SS GY VF-FG
4	-28	543		20.9	17.2	50.4	2.62	SS GY VF-FG
5	-29	64		15.0	8.2	41.2	2.60	SS GY VFG SHY
	4429-34			SHALE NO ANALYSIS				
6	-35	0.01		3.9	3.8	75.5	2.66	SS WH VF-FG CALC
7	-36	0.02		7.2	1.4	87.1	2.64	SS WH VF-FG CALC
8	-37	0.19		9.3	1.5	76.4	2.65	SS WH VF-FG CALC
9	-38	0.24		10.6	1.2	84.4	2.64	SS WH VF-FG
10	-39	250		24.1	1.8	77.2	2.62	SS WH VF-FG
11	-40	180		23.9	1.0	81.7	2.63	SS WH VF-FG
12	-41	306		25.1	1.4	73.5	2.63	SS WH VF-FG
13	-42	43		21.3	1.3	74.3	2.64	SS WH VF-FG
14	-43	74		19.1	1.9	92.3	2.64	SS WH VFG SHY
	4443-44			SHALE NO ANALYSIS				
15	-45	15		15.9	3.2	86.6	2.64	SS WH VF-FG SHY
16	-46	155		23.6	0.6	81.2	2.63	SS WH VF-FG
17	-47	32		21.0	0.6	82.2	2.64	SS WH VF-FG
18	-48	298		24.3	1.0	82.0	2.63	SS WH VF-FG
19	-49	279		20.7	1.2	79.6	2.63	SS GY VF-FG CARB INCL
20	-50	275		21.4	10.0	84.9	2.63	SS GY VFG SHY
21	-51	268		20.3	11.2	63.2	2.63	SS WH VFG
	4451-52			SHALE NO ANALYSIS				
	4452-57			LOST RECOVERY				

4438-46 CORE DROPPED & SCATTERED ON RIG: MAY BE OUT OF ORDER

(APPENDIX 2, page 1 of 2)



(APPENDIX 2, page 2 of 2)

B-1 INDUSTRIES, INC.
CORE ANALYSIS REPORT

COMPANY GARY ENERGY CORPORATION FILE NO. 121080
WELL 13-28 FORMATION MUDDY DATE 12-14-80
FIELD BELLE CREEK CORE TYPE DIA 3½" ELEVATION
COUNTY POWDER RIVER MUD TYPE WATER BASE ANALYST BP DB JC KB
STATE MONTANA LOCATION SEC 13 T9SN-R53E

SAMP NO	DEPTH	PERMEABILITY HORIZ	PERMEABILITY VERT	POR %	OIL %	WATER %	GR DNS	DESCRIPTION
1	4334-35	<0.01		0.5	15.6	67.9	2.67	SS TN FG
2	-36	812		24.9	17.7	55.9	2.63	SS TN VF-FG
3	-37	679		29.4	18.3	55.8	2.63	SS TN VF-FG
4	-38	869		25.4	19.9	60.8	2.63	SS TN VF-FG CARB INCL
5	-39	197		21.4	13.8	63.8	2.64	SS TN FG CARB INCL
6	-40	18		10.1	21.3	36.6	2.66	SS TN FG CALC
7	-41	69		10.6	0.8	71.9	2.69	SS TN FG
	4341-43			SHALE NO ANALYSIS				
8	-44	1.7		16.9	2.0	88.1	2.64	SS GY VF-FG CLY FLD
9	-45	2.1		15.7	2.2	88.6	2.64	SS GY VFG CLY FLD
10	-46	27		20.2	1.6	88.2	2.65	SS GY VFG CLY FLD
11	-47	4.7		13.8	1.9	87.4	2.63	SS GY VFG CLY FLD
12	-48	50		25.9	1.1	85.9	2.63	SS GY VFG CLY FLD
13	-49	47		23.8	6.4	83.4	2.62	SS GY VFG CLY FLD
14	-50	6.6		14.1	4.8	77.6	2.63	SS GY FG CLY FLD
15	-51	136		24.0	13.8	70.0	2.64	SS GY FG SH LAM
16	-52	26		13.3	11.4	65.8	2.62	SS GY VF-FG SH LAM
	4352-53			SHALE NO ANALYSIS				
17	-54	8.0		16.4	5.5	88.2	2.62	SS BRN VFG SHY
18	-55	4.7		19.7	7.8	77.9	2.64	SS BRN VFG SHY
19	-56	3.9		15.9	8.2	82.3	2.60	SS BRN VFG SHY
20	-57	4.2		12.6	5.6	85.2	2.60	SS BRN VFG SHY
	4357-77			SHALE NO ANALYSIS				

(APPENDIX 3, page 1 of 10)

TECHNICAL REPORT

FROM PQ ENERGY SERVICES

NUMBER 81-5T

TITLE IFT SCREENING STUDY ON "UNIT E" CRUDE OIL FOR GARY ENERGY CORP.

CUSTOMER GARY ENERGY CORPORATION

FOR BRUCE GARRETT

SUBMITTED BY
PAUL H. KRUMRINE

APPROVED
James S. Falcone Jr.

DATE
02/25/81

PQ Energy Services
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Research and Development Center
P.O. Box 258, Lafayette Hill, PA 19444
Telephone: (215) 825-5000

PQ REPORT 81-5T
(APPENDIX 3, page 2 of 10)

OBJECTIVE:

The objective of this interfacial tension (IFT) screening study was to determine the alkaline waterflooding potential and chemical requirements of the Gary Energy, Unit E crude oil in several available water sources.

SUMMARY:

Interfacial tension values were measured using a spinning drop apparatus at room temperature. The IFT values were calculated from the average oil droplet diameters measured over a 15-minute interval. Alkaline flooding potential was determined in simulated Unit E produced water and simulated Madison water versus salt levels of 0.0 to 3.0% by weight and sodium orthosilicate levels of 0.1 to 1.0% by weight.

The results of these studies showed that the interfacial tension between the crude oil and water phase was reduced by the alkaline chemicals and gave a minimum IFT at about 0.25% Na_4SiO_4 in soft saline water and a minimum at about 1.0% Na_4SiO_4 in the synthetic water. The optimum salt levels appeared to be around 1.0% NaCl. Overall, the IFT results show that this crude has only fair potential for alkaline flooding since the orthosilicate solutions did not result in IFT reduction to less than 0.1 dynes/cm.

CONCLUSIONS:

- Although IFT reduction did occur in the presence of the sodium orthosilicate, the reduction was not below the 0.1 dynes/cm level. Therefore alkaline flooding potential is expected to be only fair.

- Removal of the hardness ions by some softening process will reduce the IFT. Also, addition of about 1.0% salt will improve the IFT reduction.

- Mimimum IFT values were obtained at 0.25% Na_4SiO_4 in soft saline solutions and at about 0.5 to 1.0% Na_4SiO_4 in the Unit E and Madison waters.

RECOMMENDATIONS:

- Alkali consumption tests should be run on a sample of the reservoir material to determine the requirements of the reservoir for slug design.

- Core flood tests simulating reservoir conditions and production history should be performed using the optimum IFT chemical requirements in continuous injection and higher alkali concentrations in a short slug to determine potential alkaline recovery from the system.

DETAILS

IFT measurements were carried out on the Unit E crude oil supplied by Gary Energy Corporation. Measurements were made in three simulated waters: (1) soft, saline water, (2) Unit E water, and (3) Madison water. The simulated compositions of the Unit E and Madison waters are given in Table I. Measurements were made on a spinning drop instrument at room temperature. Readings were taken at 2, 5, 10 and 15 minute time intervals, with the reported value being the average of these measurements.

A total of 28 measurements were made. The initial tests were carried out in the soft saline water to determine the optimum concentrations of sodium orthosilicate and sodium chloride. The results of these tests are shown in Figure 1. Minimum IFT was found to occur at about 0.25% sodium orthosilicate in 1.0% sodium chloride. Higher and lower concentrations of salt resulted in higher IFT values. Increases in sodium orthosilicate above the optimum concentration resulted in slightly higher IFT values, but not significantly different.

The next tests were carried out in the simulated Unit E waters. This water was tested at four conditions versus orthosilicate concentration: (1) soft Unit E water, (2) soft Unit E water plus 0.86% NaCl, (3) hard Unit E water, and (4) hard Unit E water plus 0.86% NaCl. These results are shown in Figure 2. Removal of the hardness ions had a large effect upon lowering the IFT. A small reduction in IFT was also observed from the addition of 0.86% NaCl, bringing the total salinity up to about 1.0%, which was found to be the optimum IFT in soft saline water. The addition of sodium orthosilicate resulted in lowered IFT, but now the optimum concentration is nearer to 1.0% by weight. Some precipitate was observed in the hard Unit E water, therefore, the orthosilicate was effectively softening the water.

Six measurements were also done in the simulated Madison water. These results are shown in Figure 3. Again, the minimum IFT appears to occur somewhere between 0.5 and 1.0% by weight sodium orthosilicate. The addition of salt, however, only reduced the IFT at the lower concentration of orthosilicate; at the higher levels, the salt increased the IFT slightly.

TABLE I

SIMULATED BRINE COMPOSITIONS

MADISON BRINE:

$NaHCO_3$	0.334 g/l
NaCl	0.114 g/l
Na_2SO_4	0.606 g/l

UNIT E PRODUCED BRINE:*

NaCl	1.4434
Na_2CO_3	0.3851
Na_2SO_4	0.3032
NaOH	0.1875
KCl	0.0216
$CaCl_2 \cdot 2H_2O$	0.1896
$MgCl_2 \cdot 6H_2O$	0.137

* Softened brine was prepared similarly but with the $CaCl_2$ and $MgCl_2$ converted to an equivalent amount of NaCl.

TABLE II

GARY ENERGY CORPORATION "UNIT E" IFT STUDIES IN VARIOUS WATERS VS SALT AND ORTHOSILICATE CONCENTRATION

TEST NO	% SALT CONC.	% ORTHO. CONC.	DENSITY (gm/cc)	IFT (dynes/cm)
IN DISTILLED H_2O:				
1	0.0	0.25	1.0003	2.210
2	0.2	0.25	1.0017	0.940
3	1.0	0.25	1.0074	0.568
4	2.0	0.25	1.0145	0.869
5	3.0	0.25	1.0216	0.822
6	1.0	0.05	1.0048	3.231
7	1.0	0.10	1.0058	1.641
8	1.0	0.50	1.0105	0.761
9	1.0	1.00	1.0614	0.734
10	0.2	0.15	1.0004	2.867
UNIT E HARD H_2O:				
11	0.0	0.25	1.0021	9.588
12	0.0	0.50	1.0051	7.269
13	0.0	1.00	1.0109	3.070
14	0.86	0.25	1.0083	8.580
15	0.86	0.50	1.0112	5.470
16	0.86	1.00	1.0115	1.998
UNIT E SOFT H_2O:				
17	0.0	0.25	1.0021	2.827
18	0.0	0.50	1.0052	0.832
19	0.0	1.00	1.0110	0.658

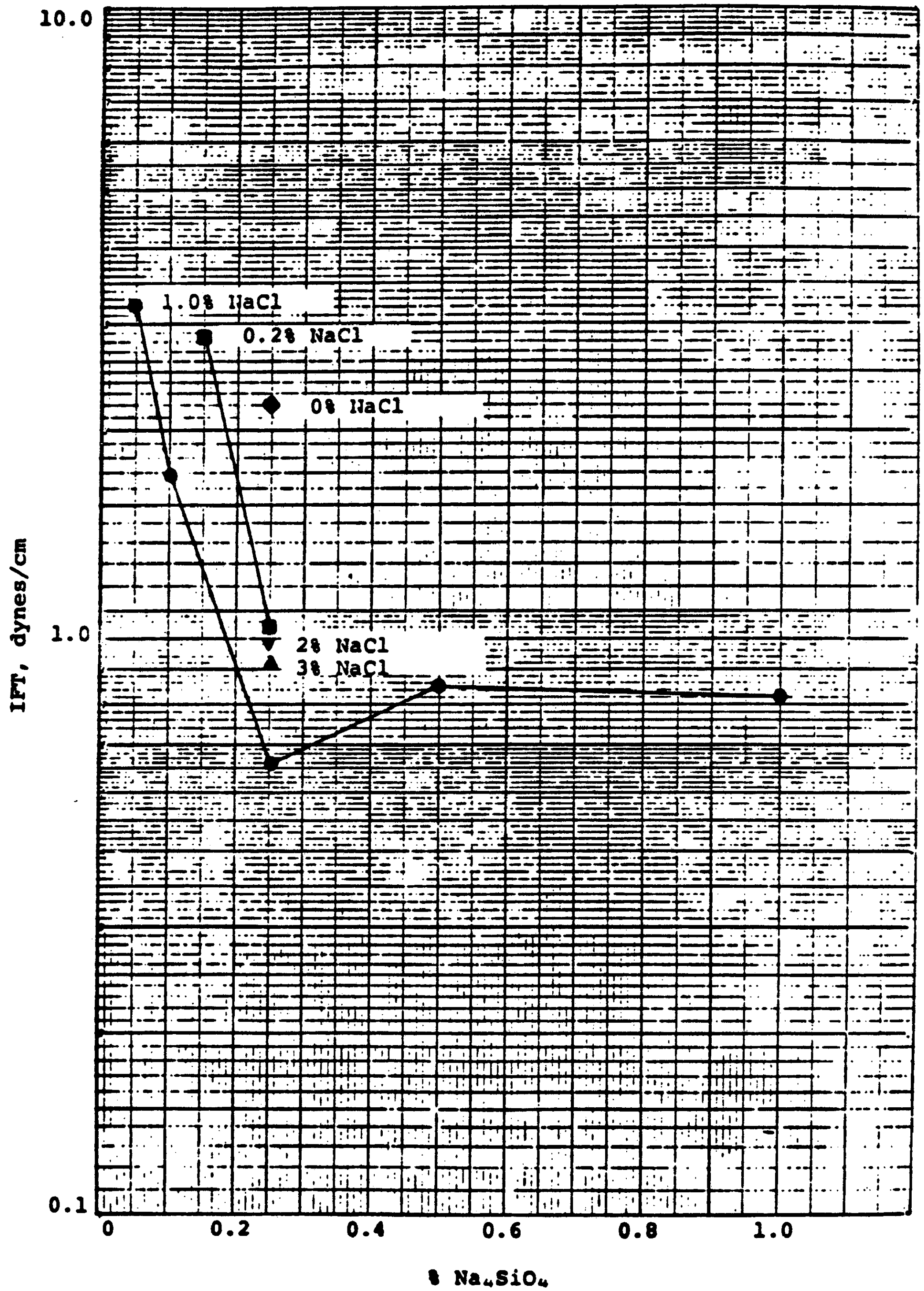
(APPENDIX 3, page 7 of 10)

TABLE II (cont'd)

TEST NO	% SALT CONC.	% ORTHO. CONC.	DENSITY (gm/cc)	IFT (dynes/cm)
20	0.86	0.25	1.0081	0.664
21	0.86	0.50	1.0113	0.627
22	0.86	1.00	1.0176	0.717
IN MADISON H_2O:				
23	0.0	0.25	1.0011	3.087
24	.0	0.50	1.0042	0.633
25	0.0	1.00	1.0101	0.534
26	1.0	0.25	1.0083	1.431
27	1.0	0.50	1.0114	0.793
28	1.0	1.00	1.0177	0.779

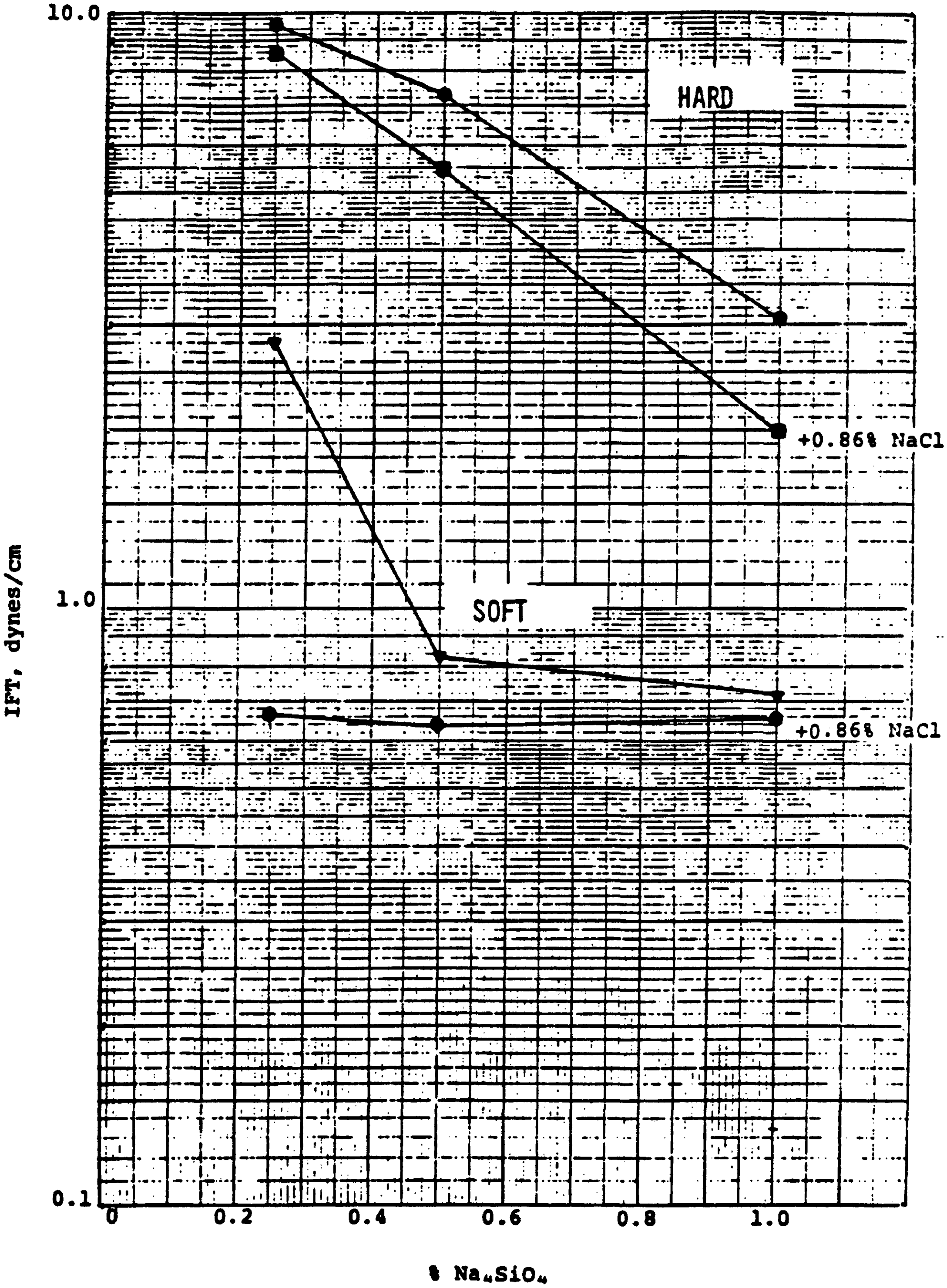
(APPENDIX 3, page 8 of 10)

FIGURE 1: DISTILLED SOFT WATER



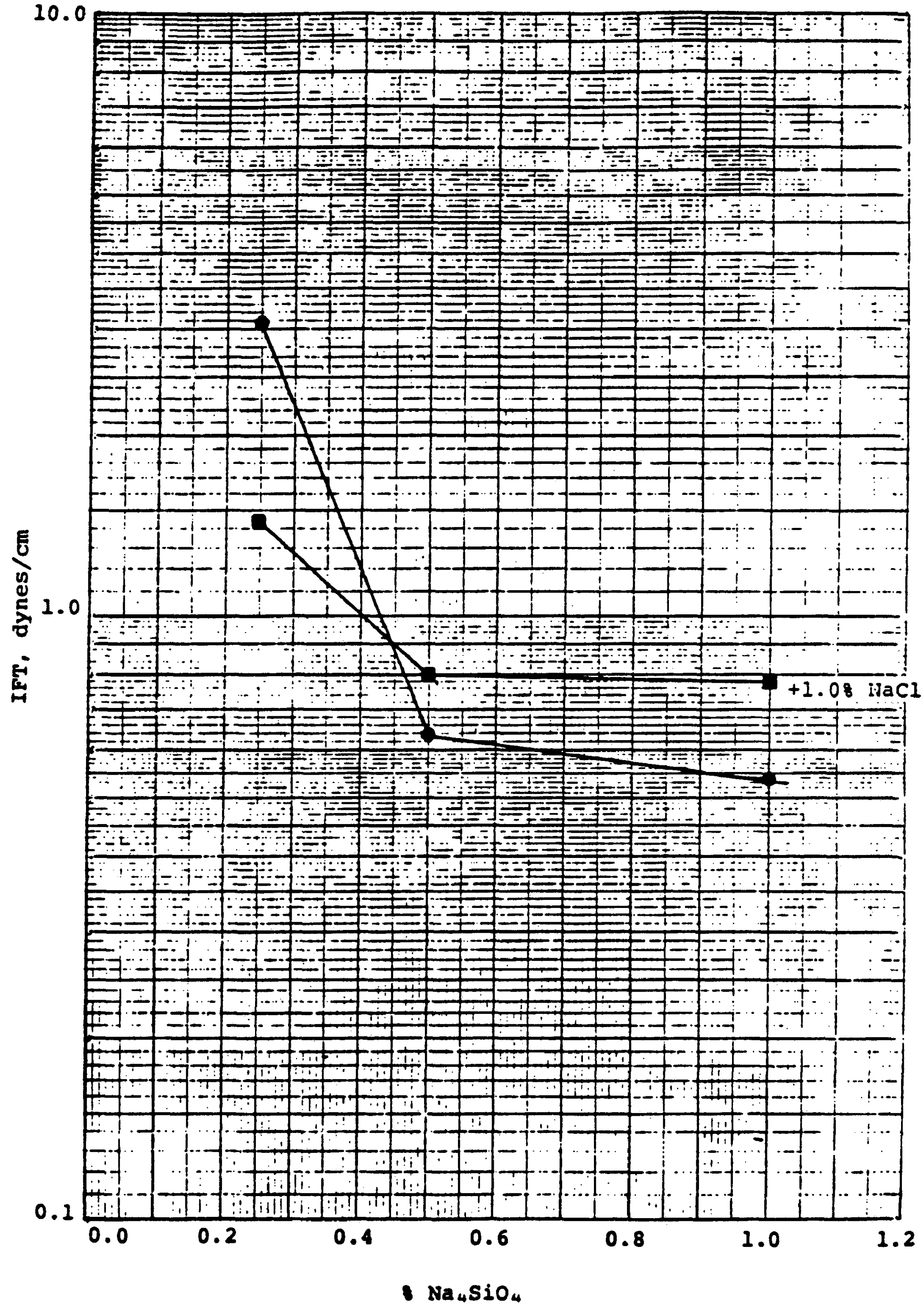
(APPENDIX 3, page 9 of 10)

FIGURE 2: SIMULATED "UNIT E" WATER



(APPENDIX 3, page 10 of 10)

FIGURE 3: SIMULATED MADISON WATER



APPENDIX 4

SILICATE AND CAUSTIC CORE FLOOD PROCEDURES

1) Core Preparation

a) Select a 2" x 12" Berea blank and pot with epoxy. Determine permeability to air at 125,250 and 500 cc/min. If the permeability is outside the 400-600 md range, discard the blank. Tare the blanks.

b) Saturate with connate water

Connate water is to be synthetic Unit 'E' injection water (SUEI). It is not to be softened at this stage. Saturation can be under vacuum, and should be conducted in a verticle position. Two recent O-Tech analyses of Tract 25 water are attached to indicate a typical range of UEI water. The key components are:

TDS as $CaCo_3$	2500-2800	mg/L
Ca	46-60	mg/L
Mg	17-18	mg/L

c) Miscibly extract the cores with toluene, followed by methanol sequentially, until clean. In Berea, this should be accomplished with one cycle. Residual methanol would then be displaced with SUEI water which should be injected at a rate sufficient to determine the specific permeability to formation water. These floods should be performed at the reservoir temperature of 110°F. Tare the blanks again to determine pore volume. If the permeability is not stable, then discard the blank. The miscible cleaning of Berea is intended to (1) establish a consistent basis for core handling when actual core material is being flooded, and (2) be very confident that the initial water saturation is driven to 100%.

d) Establish Oil Saturation

Clean the Unit 'E' produced oil by filtration through a 0.45 micron filter prior to use. Determine the viscosity before and after cleaning to monitor changes which might occur in the cleaning process. Dynamically drive the blanks with the cleaned oil to minimum water saturation. Heat the samples to 150° for 24 hours then cool to reservoir temperature and determine effective permeability to oil at irreducible water saturation.

e) Waterflood Tests

The banks would then be water driven, using SUEI water, to residual oil saturation. Incremental oil production and water production is to be accumulated and plotted. Effective permeability to water at residual oil saturation is to be independently determined. The blanks are again oil flooded with cleaned oil to irreducible water saturation and heated for 24 hours and effective permeability oil at initial oil saturation determined at reservoir temperature. The permeability in step (d) should not significantly deviate from step (e). If the deviation is more than 10 md, discard the blanks.

f) <u>Silicate Tests</u>

Ten blanks should have been prepared by steps (a) through (e). The range of blank properties acceptable are:

Ø = $\pm$ 2%

Sor = $\pm$ 5 saturation units (around 35%)

k = $\pm$ 100 md.

I. Preflush <u>Core 1</u> with 5% PV of softened synthetic Unit 'E' Injection water softened to less than 1 ppm residual hardness and spiked with sufficient sodium chloride salt to achieve a 1000 ppm, concentration of NaCl. This will be the softened SSUEI water.

Follow the preflush with a 0.2 wt% concentration of sodium orthosilicate-caustic soda mixed with SSUEI. Inject, record and plot injected water versus oil produced, instantaneous water-oil ratio and unsteady-state relative permeability. Continue the silicate flood for at least 4 pore volumes and then until the curve has flattened.

II. Preflush Core 2 with 5% PV of SSUEI. Then follow with 1.0 wt% silicate solution. Continuous flood as above.

III. Preflush Core 3 with 5% PV of SSUEI. Follow with 5.0 wt% silicate solution. Continuous flood as above.

IV. Flood Core 4 with 5% PV of SSUEI. Follow with 0.2 wt% caustic (sodium hydroxide only) mixed with SSUEI as a continuous flood.

V. Flood Core 5 with 5% PV of SSUEI. Follow with 1.0 wt% caustic solution as a continuous flood.

VI. Flood Core 6 with 5% PV SSUEI, follow with 5.0 wt% caustic solution as a continuous flood.

VII. Preflush Core 7 with 5% PV SSUEI. Follow with a 40% PV slug of 0.2 wt% silicate solution. Drive slug with SSUEI. Flood until curve flattens.

VIII. Preflush Core 8 with 5% PV SSUEI. Follow with a 40% PV slug of 1.0 wt% silicate. Drive as in Core 7.

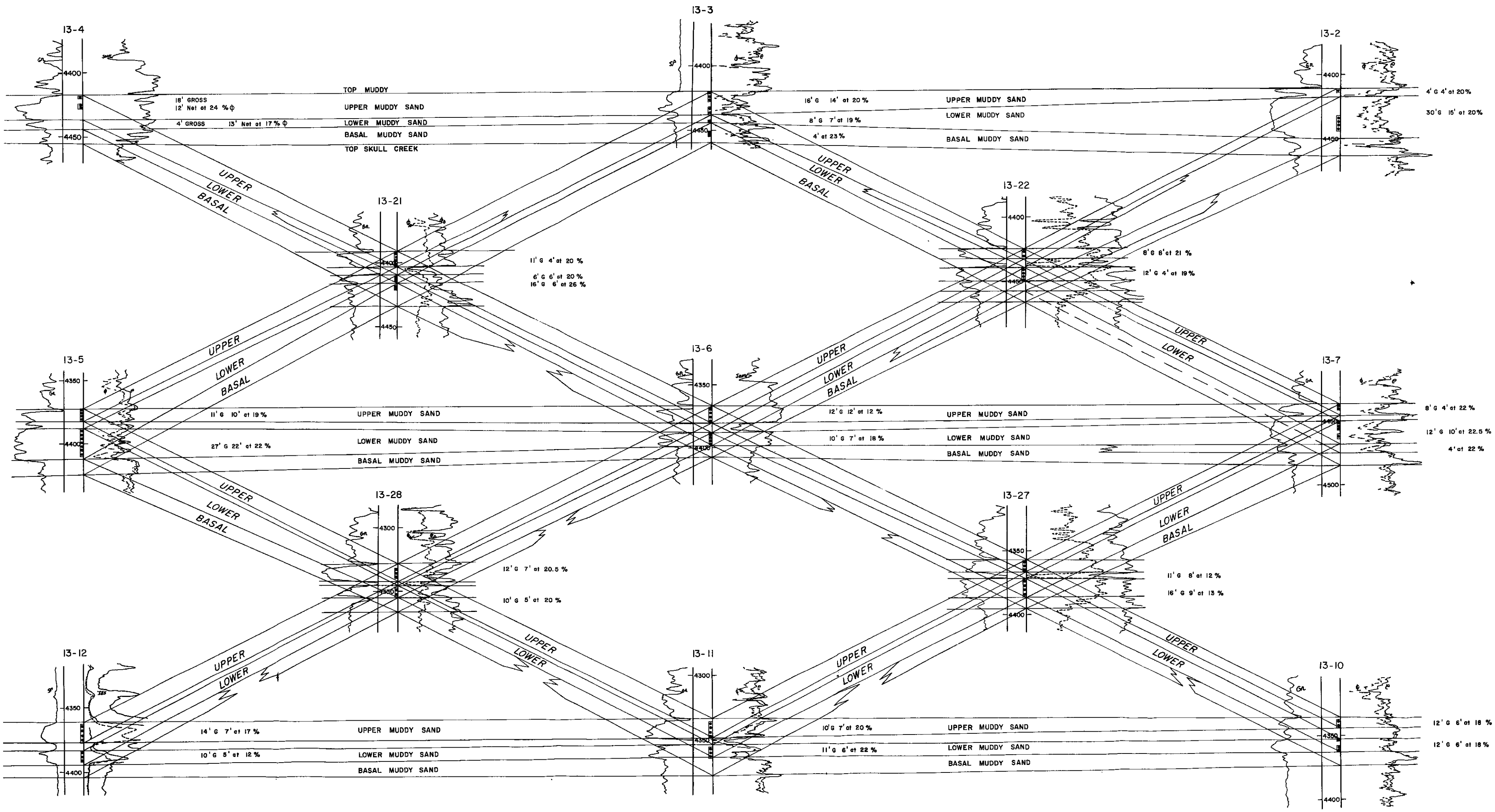
IX. Preflush Core 9 with 5% PV SSUEI. Follow with a 40% PV slug of 5 wt% silicate. Drive as in Core 7.

X. Calculate optimum flood design from above and perform flood in Core 10.

In all floods, monitor the effluent pH and plot versus injected volume.

The plots of Floods 1, 2 and 3 should indicate a decreasing incremental oil recovery with increasing silicate concentration. Floods 4, 5 and 6 should show caustic only sensitivity and Floods 7, 8 and 9 should show a depletion of active agents and a minimum slug size to achieve activity.

A plot of injection pressure vs. time should indicate the effectiveness of oil bank formation.



GARY ENERGY CORPORATION
BELL CREEK MONTANA
UNIT "E" INFILL DRILLING AREA
FENCE DIAGRAM ON TOP OF MUDDY SAND
CAUSTIC FLOOD UNIT "E" DESIGN (CFE)

DATE: 9-1-81