FOSSIL ENERGY

DOE/BC/10830-3
(DE86000279)

Evaluation of the Little Knife CO_2 Minitest

Topical Report

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Keplinger Technology Consultants
Tulsa, Oklahoma

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

Printed in the United States of America. Available from:
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

NTIS price codes
Paper copy: A05
Microfiche copy: A01

DOE/BC/10830-3
Distribution Category UC-92a

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SUMMARY

A joint DOE-Gulf Oil Corporation, nonproducing carbon dioxide minitest was conducted in the Little Knife Field in western North Dakota. At the time of the project, the reservoir was undergoing primary depletion and had no secondary recovery operations underway. The five-acre inverted four-spot tested the applicability of a CO_2-alternating-with-water injection process to commercially displace oil in the nonflooded Mission Canyon Formation located in the Williston Basin. The nonproducing test was evaluated using time-lapse logging and fluid sampling to monitor fluid movement as injected CO_2 and water displaced 41° API oil in three observation wells which surrounded a central injector. Numerical simulation studies using the time-lapse logging data provided the basis for estimating pilot performance and evaluating a proposed expansion of the process to a 160-acre pattern.

The concept of a nonproducing minitest offers the advantage of information being generated faster and at a lower cost when compared to a conventional oil-in-the-tank pilot test. There are certain inherent disadvantages in a nonproducing test which include the uncertainty in evaluating pilot performance due to the required reliance on logging and simulation analyses. Both analyses can be subject to significant inaccuracies. Lateral variations in heterogeneity could also more significantly impact minitest results compared to a conventional test. Our evaluation of the project results emphasized the analysis of logging data.

The 1.2:1 CO_2-alternating-with-water process demonstrated excellent oil displacement as measured by logging studies. In the duplication of Gulf's cased-hole log analysis results using our own petrophysical analysis tool, PETROS, we encountered considerable difficulty in estimating CO_2 saturations. Estimates of residual water saturations using PETROS compared favorably with Gulf results. PETROS calculations relied upon the Gulflog open-hole porosity calculations and sigma data reported by Gulf for water and oil. Saturation analyses of a pressure

core drilled in a swept zone qualitatively supported the result of saturations estimated from log analysis and simulation results.

An extensive amount of reservoir modeling was conducted by Gulf on the minitest area. Excellent history matches were achieved for bottom-hole pressures, CO_2 and water breakthrough times, tracer breakthrough times, and fluid saturations. Oil recovery in the minitest area from compositional simulation results was calculated to be 38.0 percent of the original oil-in-place (OOIP) for a waterflood and 48.3 percent for the CO_2 process. These results were simulated as though the observation wells were operating as producing wells and oil recoveries were based upon the oil-in-place at discovery conditions. Thus, the CO_2 process resulted in a 10.3 percent (OOIP) incremental recovery compared to waterflooding in the pilot area. Results were extended to a commercial scale application by simulating the performance expected in one quadrant of a 160-acre five-spot pattern. This simulation predicted an 8.0 percent (OOIP) incremental oil recovery for the CO_2 process compared to waterflooding in the 160-acre pattern. Gulf accepted this projection as optimistic because complex reservoir heterogeneties, water blocking, etc., were not considered in the simulator.

Gulf personnel are to be commended for designing and implementing a state-of-the-art, nonproducing pilot test of the CO_2 process. Results obtained in the pilot show an optimistic incremental recovery over waterflooding of 8.0 percent of the OOIP with an optimistic 1.0 STB of oil production estimated per 5.0 to 8.0 MSCF of injected CO_2 depending on exclusion or inclusion of Zone W. Assuming a more realistic 1.0 STB of oil recovered per 10.0 MSCF of injected CO_2, these results still encourage the commercial application of the process to the Little Knife Field upon location of a suitable CO_2 source.

INTRODUCTION

The Little Knife Field is located in western North Dakota near the center of the Williston Basin. Since its discovery on February 8, 1977, it has produced over 34.9 million barrels of 41° API crude from the Mission Canyon Formation at a depth of approximately 9,800 feet (Reference 1). To evaluate a WAG-type (water-alternating-gas) miscible displacement process in the Little Knife Field, a joint DOE-Gulf Oil Corporation carbon dioxide nonproducing minitest was conducted from December 11, 1980, through September 24, 1981.

The primary objective of the minitest was to determine the commercialization potential of CO_2 miscible displacement in dolomitized carbonate oil reservoirs that have a high remaining oil saturation. Secondary objectives included evaluation of the performance of surface and subsurface facilities and operational procedures to assist in the design of future CO_2 projects. Gulf, in their technical proposal to the DOE, divided the project into five phases (Reference 2).

Phase I:	Location and Drilling of Minitest Pattern
Phase II:	Laboratory Determination of CO_2/Water Displacement Parameters in Reservoir Cores
Phase III:	Minitest Area CO_2 Flood Simulation
Phase IV:	Injection Period -- Performance Data Acquisition and Interpretation
Phase V:	Projection of CO_2 Flood Performance to Commercial Scale

The project was carried out on a five-acre inverted four-spot (a single injector offset by three observation wells) using time-lapse logging to monitor oil, gas, and water saturation profiles. The selected injection sequence was a 1.2:1 CO_2-alternating-with-water injection process where water was injected first, followed by five alternate slugs of CO_2 and water, and finally by drive water. The observation wells were not produced; however, periodic samples were collected from these wells to measure fluid compositions and tracer concentrations. The results of the minitest were then modeled with numerical reservoir simulators to estimate the expected recoveries as a result of a waterflood compared to the CO_2 process. The sequence of major events in the life of the project is illustrated in Figure 1.

The purpose of this report is to provide a technical appraisal of the Little Knife CO_2 Minitest. This appraisal will discuss technical advances utilized in the project and suggest additional areas for study. Suggestions offered throughout the discussion are made in an effort to assist in the design and implementation of future projects and are not intended as negative comments. Gulf personnel are to be commended for designing and implementing a state-of-the-art pilot project. Their results will be of considerable benefit in future pilot test efforts.

RESERVOIR DESCRIPTION

The Little Knife Field is located near the center of the Williston Basin, south of the Nesson Anticline in portions of Billings, Dunn, and McKenzie Counties, North Dakota (Figures 2 and 3). As shown in Figure 4, the field is formed by a broad, low-lying anticlinal flexure which plunges northward, with less than one degree of structural relief, along a north-south axis. Structural closures on the north, east, and west are created by the anticlinal structure, while the closure on the south is interpreted as stratigraphic. Production is from the lower portion of the Mississippian Mission Canyon Formation. In the Little Knife Field, the Mission Canyon Formation is at a depth of 9,600 to 9,700 feet at the crest of the aniticlinal structure and is 465 feet thick.

Formation Description

The Mississippian Mission Canyon Formation at the Little Knife Field, as shown in Figure 5, is interpreted by Gulf to be a regressive carbonate sequence containing many minor carbonate cycles. The formation was divided into six zones (A through F) which differ by composition and depositional environment (Reference 3). Three of these zones (B, C, and D) make up the major production intervals. Gulf has described the intervals as follows:

Zone A, the top 60 feet of the Mission Canyon, consists of a series of thin- to thick-bedded anhydrites interpreted to be deposited in a supratidal environment. The anhydrite has both dolomite matrix and laminated interbeds of dolomite associated with it.

Zone B is a 70-foot thick series of thin, porous, lenticular dolomitized skeletal wackestone which changes with depth to a dolomitized burrowed, sparsely skeletal, pelletal wackestone/packstone. This interval of the formation was deposited in a supratidal to restricted marine depositional environment and forms the upper portion of the producing interval over most of the field.

Zone C is 65 feet thick and is interpreted to be deposited in a restricted marine to transitional marine environment. This interval of the formation grades downward from a slight dolomitized pelletal wackestone/packstone into a skeletal wackestone with some replacement by anhydrite. The top portion of this zone is somewhat porous, but the porosity decreases towards the middle portion of the zone, then begins to increase again with depth. The lower portion of Zone C forms the upper part of the productive reservoir interval in the minitest area.

Zone D, the next 50 feet, contains the lowest portion of the producing reservoir as well as the major segment of the production interval in the minitest area. It is a medium- to thick-bedded dolomitized, burrowed, skeletal wackestone interbedded with mudstones. This interval was deposited in the seaward portion of a protected shelf, which is transitional between the open marine and the restricted marine.

Zone E is 50 feet thick and composed of thick-bedded, sparsely dolomitized skeletal, mudstone/wackestone with incipient siliceous nodules. Intervals within this zone display porosity, but are nonhydrocarbon bearing.

Zone F, the lowest zone in the formation, is 170 feet thick and composed of medium- to thick-bedded skeletal packstone/grainstones and mudstones. The basal 10 to 15 feet of this zone is a transition zone between the Mission Canyon and the underlying Lodgepole Limestone.

Characteristics Of Minitest Area

The Little Knife CO_2 Minitest was located in Section 3-144N-98W and was configured in a five-acre inverted four-spot pattern. The Zabolotny Injection Well No. 1 was located 1,800 feet FNL (From the North Line) and 2,460 feet FWL of Section 3. The three monitor wells, Zabolotny Observation No. 1, No. 2, and No. 3, were in a skewed triangular pattern as shown in Figure 6. The wells were completed in the lower portion of Zone C and the upper portion of Zone D, as shown in Table 1 and Figure 7. A total of eight producing wells, including an area of 2,600 acres, was considered close enough to affect the pressure performance of the Minitest (Reference 4) in initial work to estimate reservoir pressures. In general, the Little Knife Field is about 9,800 feet deep with a 0.5 degree dip and an initial reservoir pressure of about 4,400 psi. Other basic reservoir and fluid properties data are presented in Tables 2, 3, and 4.

Analysis Of Site Selection

The minitest was carried out near the center of the field in the northwest portion of Section 3-144N-98W. Injection was in Zone D and the lower portion of Zone C. Considerations for this selection were based on:

1. Average reservoir facies,
2. Continuity of porosity, permeability and lithology,
3. Elevated structural position, and
4. Reservoir pressure no less than 3,400 psi to allow multiple contact miscibility of Mission Canyon crude with carbon dioxide.

At the time the site was selected, the producing wells were classified as BC or BCD completions based upon the completion zones (Reference 5). As shown in Figure 8, comparing static reservoir pressure versus time (or cumulative production) shows that BC and BCD completions were significantly different. BC completions displayed a pressure decrease at a greater rate than BCD completions; thus, Zones B and C exhibited relationships typical of a volumetric depletion reservoir, while Zone D displayed an active water drive. Also, core analysis, logging, and pulse testing indicated that Zones B and C had limited reservoir continuity, whereas Zone D was indicated to be a blanket deposit and continuous throughout the field, both above and below the oil-water transition zone.

The required minimum reservoir pressure to achieve multiple contact miscibility had been determined in the laboratory to be 3,400 psig (Reference 2). While any zone could be repressured through water re-injection, the average BC completion had dropped below 3,400 psig by November 1978, whereas the BCD completion averaged 4,276 psig. Under operating conditions in 1980, the reservoir pressure in BCD completions should have remained above 3,400 psig prior to the projected start date of the minitest.

A north-to-south fence diagram, shown as Figure 9, indicates that, about 1-3/4 miles directly south of the selected location, Zone D would be structurally high, but only slightly due to the low relief structure. The west-to-east structure cross-section diagram (Figure 10) shows that the site is structurally high for Zone D.

Based upon the reservoir geology (Reference 3), it is apparent that the Mission Canyon Formation contains multiple porosity developments. Because of multiple completions in the majority of wells, allocation of production back to a particular zone becomes difficult and creates problems in reservoir modeling and in selecting a representative productive interval. This difficulty does not affect how or where a reservoir test is conducted, but does affect how the results of that test are applied to the rest of the field. In a nonproducing minitest, the ability to apply the results to actual field production is a significant challenge. The major production had been from BC completions prior to the minitest, although these zones were more heterogeneous. To minimize the adverse effects of reservoir quality, it was decided to perform the test in the more porous and continuous Zone D.

The selected location satisfied the four criteria listed above. It was recognized that this site was located in a relatively homogeneous and higher quality portion of the reservoir and that test results would be expected to be optimistic in comparison to the overall reservoir.

Pulse Testing

Two series of pulse tests were carried out prior to initiating the WAG flood. The primary purpose of these tests was to determine if continuity, high permeability streaks, and/or large fractures existed between the wells in the proposed test pattern. The first test was performed after the injector and the first observation well were drilled and completed. The second test was conducted after all three observation wells were drilled and completed. The injection well served as the pulse well in both cases. In general, there was good communication between the injection well and the three observation wells. No significant fractures or high permeability channels were detected from the injection well to either of the observation wells. A summary of the results from References 6 and 7 is given in Table 5 with similar characteristics for each well. Averages from Gulf's results were a 26.2 md *in situ* effective permeabilty, 30.5 feet effective thickness, 3,812.1 md-ft/cp transmissibility, 36.611 x 10^6 md-psi/cp diffusivity, and 104.25 x 10^{-6} ft/psi storage capacity. The effective pore volumes for the area between the injector and each observation well were very similar, with a 1,310 reservoir barrels per acre-foot average effective pore volume.

Pulse testing did indicate about twice the permeability level expected from core analyses. This information combined with fracture identification log results, wave forms variable density log results, and oriented core data was interpreted as indicating the presence of small hairline fractures within the reservoir. The general trend of these hairline fractures is shown in Figure 11. For simulation purposes, the permeabilities in the northeast-southwest direction were increased 1.25 times the permeabilities in the northwest-southeast direction because of the hairline fracture trends.

PROJECT DESIGN

The Little Knife Minitest design is unique. As noted below, ARCO performed a similar pilot in the Willard Unit which served as a basis in designing Little Knife. Since the pilot was designed as a nonproducing test, the evaluation of the project is particularly dependent upon:

1. Reservoir description,
2. Simulation capabilities, and
3. Saturation measurements (logging program).

Reservoir description efforts, as described above, included extensive geologic study and interference testing. The description developed was suitable for simulation purposes.

Minitest Pilot Design

Two types of pilot test designs are typically used in the field testing of enhanced oil recovery (EOR) processes. These are logging-observation well pilots and oil-in-the-tank pilots. The primary advantage of a logging-observation well pilot is that of reduced project time. For the Little Knife Minitest, about 10 months elapsed from the beginning of water injection until the completion of project field operations. The compact time schedule of the total Little Knife Minitest program is illustrated in Figure 1. In contrast, typical oil-in-the-tank operations require from 24 to 60 months or longer for field operations. The primary disadvantage of a logging-observation well pilot is that of estimating oil recovery. For example, ARCO did not consider estimates of oil saturation remaining in CO_2 swept zones to be reliable in its minitest performed in the Willard Unit of the Wasson Field (Reference 8). This was primarily the result of uncertainty in CO_2 and water saturation estimates. Saturation results are significant since the Little Knife Minitest design was based upon the logging techniques employed in the Willard Unit (Reference 2). However, it is also significant that ARCO successfully monitored where and when CO_2 response took place, described vertical sweep from CO_2 injection, identified a definite tertiary oil bank, and developed sufficient data to prepare an estimate of incremental oil recovery to be expected in the Willard Unit (References 8 and 9). The Willard test was significantly different from the Little Knife test in that it was performed as a tertiary process and waterflood performance data were available for simulation support.

The value of logging observation wells has been demonstrated in micellar-polymer tests (References 10 through 12) and in CO_2 tests (References 8, 13, and 14), especially when coupled with fluid sampling (References 8 and 13). In these instances, observation well performance has clearly demonstrated the formation of oil banks by the given process, displacement of oil from various layers within a reservoir, and lower residual oil saturations (compared to waterflood residuals) remaining following the movement of EOR fluids through a given layer. White and Lindsays note that the minitest was designed to provide the following information:

1. Reduction in original oil saturation due to water injection,
2. Reduction in waterflood residual oil saturation due to alternate CO_2/water injection,
3. Extent of gravity segregation within the porous zone,
4. Effect of stratification and crossflow, and
5. Influence of reservoir heterogeneity on fluid injection performance (Reference 5).

These information goals appear to have been accomplished. This information was then used in simulation studies to estimate expected oil recovery. Performance prediction will be discussed in more detail in later sections.

Laboratory Studies

Laboratory studies provided the fluid properties needed to help determine the most optimal recovery process. Detailed PVT studies, fluid property studies, slim tube experiments, and core floods were performed. The resulting data were used to assist in establishing a plan of operation for the minitest (References 2, 5, 15, and 16). Sufficiently accurate equations-of-state and relative permeability curves were developed to model the reservoir fluids with simulators. As shown in Figure 12, the minimum miscibility pressure was measured to be 3,400 psig. Mobility control factors determined by varying the WAG ratio from pure CO_2 to 1:1 and to 3:1 (reservoir barrels of water to reservoir barrels of CO_2) indicated that there was little or no adverse effect of high mobile water saturations on CO_2 displacement efficiency above the minimum miscibility pressure in laboratory core tests (Reference 16). This is a rather unexpected result. Further investigation of WAG requirements was continued in simulation studies discussed below.

The WAG process has been demonstrated to significantly improve the sweep efficiency in miscible displacement processes (References 17 through 19). Early work by Blackwell, et al. (Reference 18) showed that as water-to-solvent ratios increased, oil recovery decreased. This result was confirmed by Shelton and Schneider (Reference 19) for water-wet systems; however, their work indicated no adverse effect of higher water-to-solvent ratios in oil-wet systems. Gulf data indicated that the reservoir core material was water-wet, but that the CO_2 displacement process resulted in a wettability change to oil-wet characteristics following CO_2 contact with reservoir crude oil (Reference 16). With a wettability change occurring, these laboratory results, although unexpected, are reasonable. It is interesting to note that Chevron also reported no loss of oil recovery in SACROC compositional simulation studies at WAG ratios of up to 3:1 (Reference 20).

Simulation Studies

A three-dimensional black oil simulator and a compositional simulator in one-, two-, and three-dimensional modes were used to assist in analyzing data from logs, cores, laboratory studies, field performance, and well tests. The three-dimensional black oil model was used to determine the amount and rate of pre-injection of water required to maintain minimum miscibility pressure during the minitest, characterize the reservoir, and to history match production. The compositional simulator was used to:

1. One-Dimensional Mode - match slim-tube results and roughly estimate CO_2 slug requirements.
2. Two-Dimensional Mode - refine the slug design.
3. Three-Dimensional Mode - history match minitest performance, improve reservoir characterization, compute the sweep efficiency in the minitest area, and predict expansion to a 160-acre pattern (Reference 1).

For simulation purposes, the minitest area was subdivided into four layers (W, X, Y, and Z) based upon porosity and permeability characteristics. Gulflog and core analysis comparisons for these layers are provided in Table 6.

Black Oil Model - Water Injection Simulation

The Intercomp Beta II Simulator was used to determine the future pressure conditions in the minitest area to ensure that minimum miscibility pressure would be maintained. This simulator, a three-phase, three-dimensional, pressure implicit, saturation explicit, black oil model, was used to study reservoir pressure maintenance over a 2,600-acre region affecting the minitest area.

A detailed reservoir description was developed by digitizing structural, isopachous, and isoporosity-permeability maps after analyzing log and core data (Reference 4). The initial reservoir pressure was above the bubble point of 2,698 psig prior to water injection, allowing a simplification to two phases (water-oil) since no free gas was present. Capillary pressure curves for an oil-water system were estimated for each layer by using log-derived saturations. The relative permeability curves for Layers I and II were based on cores from Sabrosky No. 4-31-4C, which is located about one-half mile directly north of the test site, and for Layer III was based on composite capillary pressure curves from wells (Klatt No. 2-19-4 and No. 3-19-4) located about four miles southwest of the minitest. Standard PVT analysis of a reconstituted Little Knife oil sample from Zabolotny No. 1-3-4A, located immediately southwest, provided the required reservoir fluid properties.

Only the eight production wells, listed in Table 7, surrounding the minitest and the injection well were judged to be close enough to have an effect on the pressure performance. Since most of the wells were completed in multiple zones, oil production was mostly water-free and the reservoir was above its saturation pressure. The only time-dependent variables were individual well pressure histories. Individual well production rates over time were prorated back to the zones of interest based on a permeability-height (kh) product to provide models with production history for each zone as shown in Table 7.

Given the previously discussed information, a pressure history match was obtained. This match was in good agreement with actual historical measurements for most of the individual wells with only the G. Hurinenko Well No. 1-2-1A showing a significant deviance of actual versus predicted pressure. This initialization provided the basis for predicting future performance of five hypothetical cases:

Number	Description
1	Naturally declining production through October 15, 1980, with no water injection.
2	Naturally declining production through October 15, 1980, with water injection beginning October 1, 1980; injection rate of 1,150 STB/D and a surface tubing pressure of 700 psig.
3	Constant rate production through October 15, 1980, with no water injection.
4	Constant rate production through October 15, 1980, with water injection beginning October 1, 1980; injection limited by a maximum rate of 1,150 STB/D and a surface tubing pressure of 700 psig.
5	Constant rate production through September 15, 1980, with water injection beginning September 1, 1980; injection limited by a maximum rate of 1,150 STB/D and a surface tubing pressure of 700 psig (Reference 4).

The results summarized in Table 8 indicate that a pre-pilot water injection of 1,150 STB/D for 15 days (Case Numbers 2, 4, or 5) would maintain the reservoir pressure well above the 3,400 psig minimum miscibility pressure. If no water was injected and production was maintained either at a naturally declining or constant rate, the reservoir pressure would fall below 3,400 psig. During the actual flood, water was injected for 27 days with an average rate of 1,094 STB/D for a total of 29,539 STB or 29 percent HCPV. The larger than planned injection was due to delays in the start date, requiring more water to repressure the area to 3,500 psi. Simulator results appear satisfactory for estimating the pressure maintenance program for the pilot area.

Compositional Simulation For CO_2 Slug Design

Initially, the compositional simulator was used in a one-dimensional mode to satisfactorily match the slim tube miscibility test results. Utilizing these results and those of the black oil model, the compositional simulator was expanded to two dimensions to optimize the slug size. Using the Peng-Robinson equation-of-state, oil and gas were represented as discrete components with vapor-liquid equilibria controlling interphase transport of these components. The ability to model fluid behavior accurately during multiple contact miscibility is important in simulating reservoir behavior. Comparisons of simulation results to experimental data for the Little Knife Field conditions were good at the pressures and fluid compositions of interest (References 15 and 21).

The results of this simulation, Figure 13, indicated that a 1:1 WAG ratio was slightly better than CO_2 alone with respect to oil recovery and much better than a 3:1 WAG ratio with respect to time:

Recovery Phase	Oil Recovery @ Breakthrough, %PV	CO_2 Breakthrough Time, Days	Ultimate Recovery, %PV
1:1 WAG	53	481	76.5
CO_2 Alone	50	447	74.2
3:1 WAG	54	662	77.5
Waterflood	26	227	41.2

The comparisons of the results were sufficient for optimizing slug size, although capture efficiency and areal sweep were not accounted for since this was a two-dimensional or cross section model. The results of this model are considered optimistic since effects such as viscous fingering and dispersive mixing were not represented (Reference 21).

Quantities And Sequences Of Injected Fluids

Based on the black oil model simulation, water injection prior to initiating the minitest was required to raise the reservoir pressure above the minimum miscibility pressure (3,400 psig) to 3,500 psi. As a result of the compositional reservoir simulation of the minitest area and laboratory tests of selected WAG ratios, a 1:1 WAG was selected as the most favorable ratio with respect to time and recovery. The WAG was divided into five cycles of 5.0 percent hydrocarbon pore volume (HCPV) of CO_2 followed by an equal amount of water on a reservoir volume basis. The WAG was then followed by injection water for the remainder of the test.

Table 9 summarizes the actual fluids injected (Reference 22). Comparing these volumes to the minitest area volumes (XYZ) listed in Table 10 shows that a project total of 258,912 reservoir barrels of water (Rbbl) or 246.6 percent HCPV was injected. CO_2 injection totaled about 2,094 tons or 22,322 Rbbl, 21.25 percent HCPV. The WAG ratio was slightly higher than the planned ratio of 1:1, with an average ratio during the WAG of 1.2:1. This result was due to the injection of slightly more water than planned during the water cycles, 5.1 percent HCPV instead of the planned 5.0 percent HCPV per phase.

Open-Hole Logging Program

The following logs were run for the open hole logging suite in the injection well and are considered sufficient:

1. Dual Laterolog-Micro-Spherically Focused Log (DLL/MSFL) with Gamma Ray and Caliper.
2. Compensated Neutron-Formation Density with Gamma Ray and Caliper (CNL/FDC).
3. Borehole Compensated Sonic with Gamma Ray and Caliper (BHC).

4. Wave Forms-Variable Density (Wave Forms/VDL).
5. Fracture Identification Log with Gamma Ray (FIL).
6. Continuous Directional Survey (CDR).
7. Gyroscopic Multi-Shot Survey.

Excluding the Continuous Directional Survey (CDR), the Zabolotny Observation Well No. 1 had the same suite of logs as the injection well. Since the agreement between the two surveys was good, only the Gyroscopic Multi-Shot Survey was run in the observation wells. Results of the surveys were used to correlate logs to actual depths and identify the wellbore locations as shown in Figure 6.

The following logs were run for the second and third observation well (Zabolotny Observation Well Nos. 2 and 3):

1. DLL/MSFL with Gamma Ray and Caliper.
2. CNL/FDC
3. BHC with Gamma Ray and Caliper.
4. Gyroscopic Multi-Shot Survey.

TDT Time-Lapse Logging Program (Cased-Hole)

Since the wells were not produced, the most critical measurement of the minitest performance was the change in fluid saturation over time. The initial oil, water, and CO_2 saturations and the saturation changes during the flood were calculated by the use of a Thermal Neutron Decay Time (TDT) log. The change in the saturations after the start of the fluid injection phase of the minitest was interpreted as an indication that injected fluids were affecting the observation wells. An initial TDT logging suite was run on each well to determine the original conditions of the reservoir for comparison with reservoir conditions at various times during the flood.

To determine if the data accumulated by this testing procedure are valid, it must be established that a TDT log will give valid results in the Little Knife Field. The following table describes the conditions at which a TDT log gives the best results and the conditions present at Little Knife Field.

Favorable Conditions	Little Knife Conditions
Liquid filled casing with water containing greater than 50,000 ppm TDS	162,000 ppm*
Small borehole and pipe sizes (less than 9" csg)	5-1/2 OD
Temperature limit of 300°F	240 - 245°F
High porosity (greater than or equal to 15 percent)	Avg. 19.5%
Reasonably shale-free	No Shale

* Higher salinities observed in samples from other portions of the reservoir.

All of the above conditions that were required for good results with a TDT log were met at the Little Knife Field. After correction of the TDT logs, the saturation values obtained should be representative of the true reservoir conditions.

To establish the initial conditions, each observation well was allowed to produce in order to clean the perforations, dissipate formation damage, and re-establish original fluid saturations (as closely as possible). In each case, a log-flow-log procedure was carried out until no significant changes occurred between subsequent logging runs, indicating that fluid saturation had stabilized around the wellbore.

Prior to the interpretation of any TDT log, the logs were tested for proper calibration; and, if any miscalibration was found, the entire log was adjusted for the offset and gain. The corrected log was used for subsequent analysis.

PROJECT IMPLEMENTATION

Pattern development was designed to provide the necessary data to properly evaluate the minitest. New wells were drilled to perform the test, allowing complete control over how the test would be conducted. It appears that Gulf went to great lengths to provide the best possible operating conditions:

- Solids removal equipment was utilized in drilling to reduce formation damage.
- Coring fluids and cement slurry programs were designed to optimize data acquisition.
- Whole cores were taken from all wells.
- An extensive logging program was established to statistically reduce error and provide a baseline condition for monitoring saturation changes over time.
- Pulse testing established permeability trends and fractures.
- An extensive time-lapse logging program monitored fluid saturation changes.
- A fluid sampling program monitored fluid composition over time to assist in log analysis and saturation determination.

As a result, the project experienced minimal equipment problems and none that adversely affected the outcome of the project.

Data Collection

The collection of data for this project appears to have been thorough and well planned. Each phase of the project was carefully monitored, and a back-up system was available for critical items. This approach was taken to ensure that the test would not fail due to equipment, supplies, or lack of data. Listed in order of importance are some of the more important data collection steps taken:

1. A TDT logging program was set up to make five passes on each observation well every month until water breakthrough occurred. Thereafter, each well was logged every two weeks.

2. Fluid injection was carefully monitored to ensure that the proper amount and quality of water or CO_2 was injected. In the case of CO_2, Gulf employed a liquid flow meter as well as a gas flow meter.

3. Pressure was recorded continuously for the injector and the observation wells. Helium-filled 0.094 stainless steel capillary tubing was connected to pressure chambers located in the tubing string just above the packers and extended to two pressure recorders located in the trailer. Each observation well had two chambers and lines, and a manifold system in the trailer allowed either the top or bottom chamber to be monitored. Because of narrow wellbore conditions in the injector, only one pressure chamber existed.

4. The fluid sampling was very similar to the TDT logging program. Each well was sampled once a month until February 1981, at which time samples were taken every two weeks.

5. An oriented whole core was obtained on every well. Directional permeability measurements were obtained for each foot of the pay interval.

Surface Facilities

A schematic of the minitest site is shown in Figure 14. The instrumentation and equipment can be broken down into three areas:

1. Water Injection System,
2. CO_2 Injection System, and
3. Fluid Sampling System.

The trailer located north of the injector was the central point of operations. The salt water filter, tanks, and pumps located in a central production facility were the only equipment located outside of the test area. Due to the limited amount of electrical power, most of the equipment at the test site was powered by propane.

Water Injection System

The water injection system, illustrated in Figure 15, consisted of storage tanks, filters, and a transfer pump in the Central Tank Battery No. 2, and an injection pump located near the injection well. A fiberglass line connected the tank battery and the injection pump. The tracer injection pump was located in the test area with the triplex water injection pumps.

The produced formation water from the central tank battery was used as injection water. The water was filtered using an upflow, graded sand unit. During a 30-day test, the water density remained essentially constant. No quality control problems were encountered.

An isopropyl alcohol tracer was injected with the initial injection water, and n-propyl alcohol was injected as a tracer during WAG water injections. Tracer injection concentrations were about 25 gallons per day or 0.05 percent by volume. Fluids sampled throughout the project were analyzed for these tracers to provide additional information about fluid movement by indicating the point of breakthrough. Both tracers were successful in showing breakthrough of the initial injection and WAG brines. In all cases the brine banks were detected as expected, i.e., initial brine was detected in observation wells before WAG brine.

CO_2 Injection System

Liquid CO_2 was transported to the test site by truck from Brandon, Manitoba, Canada and stored at 0°F and 300 psig. A storage capacity of 200 tons (one-half of the volume of CO_2 required per cycle) was installed to ensure that the CO_2 supply would not hinder the injections due to delivery problems. Since it was planned to complete the CO_2 injections during the winter months, the storage tanks were not refrigerated. Ambient winter temperatures normally would be low enough to minimize CO_2 loss. However, an abnormally warm winter did create gas-locking in the injection pump suction. This problem was alleviated by painting the injection line silver, covering the pump, and spraying liquid CO_2 onto the suction end of the pump. Except for the problem caused by the weather, the CO_2 injection system performed with minimal interruption. A diagram of the CO_2 injection system is given in Figure 16.

The CO_2 C^{13}/C^{12} isotope ratio was measured on CO_2 native to reservoir fluids and on the injected CO_2. Differences were sufficient to allow the isotope ratio to be used as a CO_2 tracer. The CO_2 breakthrough was readily determined in fluid samples from each observation well.

Fluid Sampling System

A three-phase separator, as shown in Figure 17, was used to monitor the observation wells. The unit was enclosed, skid-mounted, and equipped with a catalytic heater to prevent freezing. The unit was vented at 1,000 barrels per day and 2 MMSCF per day at 200 psi and contained a pressure gauge, thermometer, backpressure valve, and glass sight gauge.

Sampled fluids flowed from an observation well through the manifold into the separator and were collected in water or oil tanks with the gas being flared. The wells were allowed to produce enough fluid to take representative samples for analysis of fluid composition, tracers, and CO_2 content.

Fluid samples were obtained from all the observation wells on a monthly basis until February 1981, at which time the samples were taken once every two weeks to ensure that the CO_2 front would not pass the observation wells without detection. The subsurface samples and a separator gas sample were obtained until the water breakthrough occurred. At this point, a gas lift was necessary to collect the separator gas samples. On the day prior to taking the fluid sample, the wellhead pressure was reduced to 0 psia to remove most of the residual N_2 from the last gas-lift operation. On the day of the test, the wellhead pressure was again reduced to 0 psia, and a gas sample was taken immediately before the gas-lift operation began. A subsurface sampler was then used to collect a fluid sample after 10 barrels of fluid had accumulated in the separator.

Well Completions

Each well was completed very similarly with only slight differences between the injector and the three observation wells. A combination string of 5-1/2-in. OD, L-80, R-III, 8rd LT&C casing was run with weight below the DV collar of 23.0 lbs/ft and 17.0 lbs/ft above it. The tubing used was 2-7/8-in. OD, 6.5 lb/ft C-75, R-2, CS-CB with premium threads to obtain a bubble-tight seal. Various tubing nipples on the bottom of the packer assembly were installed for a corrosion study. The landing nipples were made of Inconel 7/8, one of the most corrosion-resistant materials tested. Completions appear to have isolated produced fluids such that samples collected would be expected to represent fluids from Zones C and D.

Packers contained Nitrile packing elements and Viton O-rings. Seals were also made of bonded Viton. Additional seal units were provided to allow for expansion and contraction of the tubing. Since the minitest was a nonproducing test, seals and down-hole equipment did not experience the more adverse conditions expected from regularly producing H_2S, CO_2, and water mixtures. No severe problems with corrosion or seal failures were noted.

In the injection well, the tubing was coated inside and out with TK-2. Both Gulf and the service company concurred on the TK-2 coating based on prior tests and usage. However, the observation wells were coated with TK-7 instead of TK-2 because of prior field experience at the SACROC CO_2 project in the Kelly-Snyder Field, Scurry County, Texas. Laboratory test results reported in Reference 24 indicated better performance for TK-7 when H_2S was present. This condition would be more typical of a producing well.

Other differences found were that the injection well had only one PTS (pressure transmission system) concentric chamber as opposed to two in each of the observation wells. The chambers were made of J-55, and the coatings used were TK-2 and TK-7, depending on the well type. Observation wells required gas-lift mandrels with wireline retrievable gas-lift valves because there was not enough formation pressure to initiate flow for obtaining representative samples.

TECHNICAL ANALYSIS

There is no "oil-in-the-tank" measurement to confirm any conclusive statements concerning oil recovery. The most important factors in evaluating the nonproducing minitest performance were the time-lapse log analysis (how much oil was displaced and where) and the numerical simulation of the oil recovery in the minitest area from the CO_2 process. Without meaningful oil, water, and gas saturations over time and depth, no extrapolation of data to ultimate recovery or production performance could take place with any degree of validity.

Even with this information, the results can still be questionable as in the case of the Willard Unit of the Wasson Field (References 8 and 9). Although the Willard Unit Minitest was performed in conjunction with a larger field test, the ability of the minitest results to measure the larger scale test performance was not evaluated because the larger test was shut down prematurely due to an unfortunate accident (Reference 25).

Time-Lapse Log Analysis

This analysis reviews and evaluates Gulf Oil's analysis of several monitor Neutron Thermal Decay Time logs taken during the Little Knife CO_2 Minitest. TDT (thermal decay time) logs were run on Zabolotny Observation Wells Nos. 1, 2, and 3 approximately every two weeks after water breakthrough. Due to the vast amount of log data available on Observation Wells Nos. 1, 2, and 3, it was impractical to analyze each and every monitor run under the scope of this project. Hence, only the base, first monitor, and last monitor logs were used in this evaluation. Our evaluation was carried out using our own proprietary petrophysical evaluation system, PETROS (Reference 26).

Data Preparation

TDT log data were supplied by Gulf/Chevron on digital LIS format tapes, with the exception of a few runs in which only analog data were available. When available on tape, all passes for the TDT run were read into a PETROS data base and stacked so that statistical variations were minimized. This method is similar to that discussed by Gulf (Reference 27). Since the digitizing process introduces statistical errors in itself, only one pass was hand-digitized for TDT runs supplied in analog form. A mild three-point filter was then applied to each hand-digitized curve. This common practice accomplishes much the same effect as recording several passes of a single log. It serves to reduce the effect of spurious variations due to statistical fluctuations or digitizing errors. No tape data were filtered because the process of stacking passes readily corrected for statistical variations.

All logs were depth corrected to a base log using an interactive graphics routine specifically designed for this purpose. For consistency throughout the study, the effective (or shale corrected) porosity derived from the open-hole log data of each well served as the base curve. Effective porosities were found on one of several answer tapes that were available for each well. Gulf's open-hole porosity curves correlated well with core analysis and were considered acceptable for use in our analysis.

Evaluation Techniques

Initial formation water saturations (base log) were calculated from cased-hole logs for the injection well and the three observation wells using Gulflog porosities. As demonstrated in Reference 1, Gulflog porosities were in good agreement with core data for each of the pilot wells. For the zones of interest, water saturations for the base log were in reasonable agreement with Gulflog open-hole results. Since reasonable agreement was noted, the cased-hole (TDT) initial water saturations over the zones of interest were set equal to Gulflog results. Using this base log, water saturations were then calculated for the first and last monitor TDT logs. Gulf's published sigma values (Reference 28) were reasonable and were, therefore, used in these calculations. It should be noted that various sigma values for water were reported by Gulf (References 27, 28, and 29). These values ranged from 147 to 180 c.u., with the values of 162 c.u. (basic runs) and 147 c.u. (subsequent runs) appearing to be the most reasonable.

Results

Although inital formation water saturations calculated were in reasonable agreement with Gulf's results for the zones of interest (C and D), no correlation in results was shown for Zone E. Zone E was reported to be a high-porosity, water-saturated zone suitable for TDT log calibration purposes. Differences may have been caused by our using an erroneous sigma water value (we assumed 147 c.u. since Gulf reports did not identify which sigma value was used) and/or an erroneous sigma matrix value (no information provided). Also, no shale correction was used in our calculation since Zone E was described as being relatively shale free. Observation Well Nos. 1, 2, and 3 averages of final water saturations for the W, X, Y, and Z layers are shown in Table 11. Gulf's averages, from Reference 30, for these layers are included for comparison. In general, the results compare favorably with Gulf's results with an overall average water saturation of 48.3 and 49.2 percent pore volume, PETROS and Gulflog, respectively.

For example, averages of final water saturations for Zabolotny Observation No. 1 layers W, X, Y, and Z are 46.4 , 43.9, 59.5, and 53.2 percent, respectively. Gulf's results for the same layers are 47.0, 55.3, 59.8, and 40.1 percent. The large discrepancies noted for layers X and Z are probably due to the limited number of samples in these layers. Layer X is only two feet thick (9,809 to 9,811) and layer Z is four feet thick (9,821 to 9,825). These intervals are not thick enough to expect accurate correlation, as minor depth discrepancies can introduce large errors over such short intervals.

Figures 18, 19, and 20 depict the results of the water saturation calculations, as well as bulk volume plots showing the displacement of hydrocarbons, CO_2, and crude oil by the flooding process for each well. The curves plotted in each of the six tracks are described below, as well as on the plots:

TRACK 1: SIGMA FROM BASE, FIRST MONITOR, LAST MONITOR
TRACK 2: RATIO FROM BASE, FIRST MONITOR, LAST MONITOR and POROSITY
TRACK 3: SW FROM BASE, FIRST MONITOR, LAST MONITOR
TRACK 4: BULK VOLUME BASE (POROSITY and WATER SATURATION)
TRACK 5: BULK VOLUME FIRST MONITOR
TRACK 6: BULK VOLUME LAST MONITOR

Figures 21, 22, and 23 are comparisons between Gulf's final monitor water saturations and the final monitor water saturations computed by PETROS for Zabolotny Observation Well Nos. 1, 2, and 3, respectively. The Gulf final monitor water saturations were taken from Figures A-11, A-23, and A-33 of Reference 30. The oil saturation curves (So) and gas saturation curves (Sg) were digitized from these figures, added together, and then subtracted from unity to derive Sw. For Zabolotny Observation No. 1, the last monitor run occurred on September 16, 1981, but Figure A-11 of Reference 30 is dated August 25, 1981. This is the last plot of Well No. 1 that is available in the report, and it should be noted that for Well No. 1 Gulf's calculations precede ours by one month. An effective porosity curve based on Gulf's work is also plotted. The overall water saturation based on PETROS is lower than that computed by Culflog. This indicates slightly lower oil recovery than that computed by Gulf.

The triangulation calculation technique described by Gulf is unique and appears useful (References 27 through 29). However, we were not successful in calculating CO_2 saturations using the technique. Excellent results were achieved in calculating water saturations by this method. A probable reason for differences in the calculations is that the amount of free CO_2 at the high end is only 3.4 percent of bulk volume. The ability to extract such a minor contribution from the total pulsed neutron signal is questionable. We did not correct for environmental factors using gradiometer data, which is recommended by Gulf (Reference 28), since these data were not available. However, in Figure 2 of Reference 28 these corrections seem insignificant when compared to actual log values of sigma and ratio.

In previous work by ARCO, the Compensated Neutron log was used in conjunction with the Pulsed Neutron log to estimate CO_2 saturations (Reference 8). Gulf in this work was using the Dual Spaced Pulsed Neutron tool to measure thermal neutron capture cross section (sigma) and a near-to-far detector count ratio. The near-to-far detector count ratio was thought to be similar to a compensated neutron ratio measurement and, therefore, suitable for estimating CO_2 saturations (Reference 28).

In using a triangulation technique, it is imperative that the vertices of the triangles be well defined, especially when small volumes, such as CO_2 in this case, are involved. The vertices for oil and water are easily defined, and the method is described in References 27 and 28. The location of the CO_2 point is somewhat more involved as the sigma and ratio of a pure gas is difficult to measure. In Reference 27, it states that the sigma CO_2 point was established by replacing the oil and water in the porosity with CO_2 and solving volumetrically with the ratio of CO_2 equal to the ratio of the matrix. In Reference 28, however, it states that sigma CO_2 was calculated using formation conditions of pressure and temperature and the capture cross-section of carbon and oxygen. The ratio response of CO_2 was assumed due to the lack of experimental data. The parameters used were sigma CO_2 = 0 and ratio CO_2 = 0, yet the actual determination of these parameters remains unclear. In summary, Gulf's analysis of the monitor logging process may be a valid application of the triangulation technique described in References 27 and 28, though further clarification of the model and applicable corrections to the raw data is necessary before the method can either be accepted or condemned.

Reservoir Simulation Studies

In the final analysis of pilot performance, Gulf used a 640-acre model to evaluate the minitest performance (References 1, 23, and 31). The model included only the three producing wells immediately surrounding the minitest: Zabolotny 4-3-1A, 1-3-4A, and 2-3-3A. Grid patterns of 11x11x2, 11x11x4, and 16x15x4 were used. In the minitest area, the 11x11x2 grid was used to match bottom-hole pressures at the injector and observation wells, as well as water and CO_2 breakthrough times. Additional work indicated no significant differences in bottom-hole pressure matches using either of the three grid systems.

To study stratification effects, the model was expanded to 11x11x4 which corresponded to the W, X, Y, and Z layers previously discussed. The 16x15x4 grid was used to simulate the entire 640 acres. In general, the model predictions were similar to those estimated by log analysis and fluid sampling. For example, Figures 24 through 26 illustrate the oil saturation history matches for Zone D (Layers X, Y, and Z combined) obtained for Observation Well Nos. 1, 2, and 3. These results, obtained with the 16x15x4 grid, show good agreement with log derived saturation data. In general, good history matches were obtained for saturation profiles, pressure history, tracer profiles, CO_2 breakthrough times, etc. The reader is referred to References 1, 23, and 31 for further comparisons.

The simulation results shown in Table 12 indicated that the waterflood and CO_2 processes displaced 37 and 50 percent, respectively, of the oil-in-place in the pilot area on December 11, 1980. When the model allowed all three observation wells to be produced, the recovery dropped to 34 percent for waterflood and 45 percent for the CO_2 process. Based upon another simulation study which was not discussed, natural depletion on December 11, 1980, had reached about six percent of original-oil-in-place (OOIP). Thus, oil recovery based on OOIP is 38.0 percent for primary plus waterflooding and 48.3 percent for primary plus the CO_2 process. These results are summarized in Table 13. Note that these results for operating the test area as a producing test differ somewhat from results reported in Reference 1.

The observation well pilot showed a reduction in oil saturation due to the CO_2-water process and the saturation reduction observed by logs was qualitatively supported by a pressure core. Further, the assumptions and model calculations discussed above appear reasonable; however, without the produced liquid volumes, for cross-checking, there is some uncertainty in estimating swept volume, oil rate and total oil recovered.

Tracer concentrations are helpful to identify flow between injector and observation wells, but, again without the production rate and cumulative volume it is necessary to make additional assumptions to calculate sweep and oil recovery. Keep in mind that a small error in estimating saturation from logs can result in larger error in liquid rate and cumulative volume. With the qualification discussed above, the effectiveness of the CO_2-water process can be discerned from Tables 10 and 12. Assuming the primary recovery was by volumetric expansion, it can be estimated that the combined sweep, displacement and oil swelling by CO_2 was about 50 percent of HCPV. The log saturations and the computer simulation suggested an incremental recovery of about 11,000 bbl STO (as estimated from Table 12), resulting from the injection of about 36.1 million SCF CO_2 (as in Table 9), or about 3.3 SCF CO_2/bbl STO.

The data from the observation well pilot were used to simulate results first in a 5-acre production pilot, then in a 160-acre 5-spot. A 10x10x4 rectangular grid was used to model one quadrant of a 160-acre 5-spot pattern. An attempt was made to account for the fact that the top most layer, W, was not perforated in either injector or producer, yet oil recovery was obtained from that layer. However, the complex heterogeneity present in the reservoir on a field wide basis was not considered in the simulator.

The incremental recovery calculated for the 160-acre pattern is shown in Table 13 to be 8 percent OIP. Although this recovery estimate should be used advisedly, it may be combined with a further assumption about CO_2 injection to give a ratio of CO_2 to oil recovered. A CO_2 injection to incremental oil recovery of 8 MSCF/bbl STO is obtained if a 21.25 percent HCPV based on the total of all four layers, including W, is assumed. The combined total sweep, displacement and oil swelling by CO_2 in the 160-acre 5-spot calculated from Table 13 using the same assumptions as for the observation well pilot is 48 percent of HCPV.

Fluid Analysis

The primary objective of the fluid sampling program was to obtain data to verify the logging results. The program developed by Gulf met these objectives and provided valuable data that substantiated the logging analysis and simulation studies. The selection and use of tracer enhanced the results considerably and should be considered as a model for future projects to follow.

Pressure Coring Analysis

Zabolotny Observation Well No. 4 was drilled in a portion of the reservoir thought to have been processed by injected fluids (References 32 and 33). The purpose of this well was to provide a pressure core to enable independent measurements of residual oil saturations in swept zones of the pilot area. In this well, residual oil saturations were measured by open-hole logging and by saturation measurements of pressure-core samples.

Considerable care was provided in the design of coring fluids and operations to minimize flushing of the pressure-core material. This care included the use of tritium as a tracer in the coring fluid. In spite of precautions, tracer analyses indicated that most of the core material was extensively flushed with mud filtrate. As a result, oil saturations measured are typical of residual oil saturations. A comparison of log-derived with core-analyzed oil saturations is provided in Figure 27. Note that core saturations are typically much lower than log-derived oil saturations. However, for the case of CO_2-swept zones, oil saturations determined by the two methods are in qualitative agreement. These results qualitatively support the results of lower oil saturation measurements by log analysis in swept zones, in that residual oil saturations occurring in these zones prior to coring (waterflooded or CO_2-swept zones) would not be expected to be significantly altered by flushing during coring operations.

Note that open-hole logging operations were performed. Saturations derived from logs may represent slightly lower oil saturations than are representative of the reservoir due to mud filtrate invasion.

Corrosion Study Analysis

Gulf tested a wide range of material during the minitest in an effort to provide data for future selection of material under the operating conditions present at Little Knife during a CO_2 flood. We concur with Gulf's findings that overall performance of the materials used was good, but the results are not conclusive for a production environment. All corrosion testing was carried out under "un-stressed" conditions. Corrosion in observation wells could have been much higher had the wells been continuously produced. The only major corrosion problem was the chipping of the plastic coatings due to wireline and logging tool work.

ECONOMIC ANALYSIS

To establish a successful enhanced oil recovery project, it is imperative that the economics justify the increase in capital and operating costs over those of primary recovery and/or waterflood. The Little Knife Minitest gives every indication that it was a technological success. Unfortunately, the data required to evaluate the economics of this project or a larger project were not presented. In fact, an economic analysis of current operations, a waterflood, or a CO_2 flood was not presented by Gulf in the final report.

CO_2 Source

A major consideration in designing a CO_2 field-wide flood is the source of CO_2. There is no known naturally occurring CO_2 source in the Little Knife area. The planned source was the Great Plains coal gasification plant located 50 to 60 miles east, but recent public announcements have indicated that this source may not be available (Reference 34). Since there are no known natural CO_2 sources immediately available, further consideration of the economics to Little Knife may not be appropriate. However, the information from this project is thought to be of significance to similar reservoir types in other locations. A secondary CO_2 source needs to be located for future consideration of a CO_2 flood in the Little Knife Field. One possible alternative natural source is the LaBarge Field located in southwestern Wyoming.

CONCLUSIONS

The primary purpose of the minitest was to determine the commercialization potential of CO_2 miscible displacement in dolomitized carbonate oil reservoirs that have high remaining oil saturations. Simulation studies presented an optimistic 8.0 percent (OOIP) incremental oil recovery on a 160-acre five-spot pattern at an estimated CO_2 requirement of 5.0 MSCF/STB. This is an unusually low CO_2 requirement. If this CO_2 requirement were doubled to a more realistic 10.0 MSCF/STB, a reasonable estimate for a heterogeneous reservoir, CO_2 costs per barrel would indicate borderline economics. Thus, the project would encourage application of the CO_2 process to Little Knife.

In general, the Little Knife CO_2 Minitest was a technical success. The design, planning, development, operations, and analytical procedures were excellent. Each phase of the project was carried out in a professional manner, and it is obvious that the project was given considerable time and expense. A logging-observation well pilot has the primary advantage of reduced project time; however, it suffers a disadvantage due to the increase in uncertainty in estimating oil recovery. In such a test it is difficult to confirm estimates of oil recovery. For instance, tracer analyses confirm fluid movement within the pilot area. When tracer concentration data are combined with volumetric data, it is possible to characterize heterogeneity and flow characteristics within a pilot area. In the absence of volumetric data, as is the case in a nonproducing test, no estimate of pilot area heterogeneities can be prepared from tracer data. Gas-oil and water-oil production data are also useful tools in the estimation of fluid saturations in a pilot area. Again, in a nonproducing test such as the Little Knife Minitest, these data are not available for confirming log analysis saturations. It should be remembered that the pressure core work did qualitatively support log analysis results. Most importantly, the Little Knife Minitest did demonstrate the ability of the CO_2 process to reduce residual oil saturation to significant levels below that of waterflooding.

Some of the findings included:

1. Log analyses obtained with Keplinger's PETROS and with Gulf's Gulflog are in good agreement. Gulflog results were slightly more optimistic but not significantly. Overall, residual water saturations were calculated to be 48.3 percent by PETROS and 49.3 percent by Gulflog.

2. In general, the reservoir simulation history matches were in good agreement with measured values. Displaced oil recovery of original oil-in-place on December 11, 1980, averaged 38.0 percent for a waterflood and 48.3 percent for the CO_2 process for the case of operating pilot observation wells as producers.

3. Under the assumption that the observation wells were produced, the calculated oil recovered is 34 and 45 percent for the waterflood and the CO_2 processes, respectively. Assuming that a total of 6.0 percent of OOIP was previously recovered, the oil recovery based on OOIP was 38.0 percent for primary plus waterflood and 48.3 percent for primary plus the CO_2 process.

4. An expanded simulation to 160-acre spacing indicated oil recoveries of 40 percent for a waterflood and 48 percent for the CO_2 process when evaluating one quadrant of an inverted five-spot pattern. This result appears optimistic when considering that reservoir heterogeneities known to exist in the field were not included.

5. The project definitely indicated the movement of oil as a direct effect of the CO_2 process. Because the project was not produced, it is uncertain how much oil would have been recovered. Simulation results indicate that a strong potential exists for commercialization of the CO_2 process in the Little Knife Field. However, during the time that has passed, the average reservoir pressure has dropped significantly below the minimum miscibility pressure, and the reservoir will have to be repressurized.

6. There was not enough data to substantiate an economic analysis; however, the planned source of CO_2 is in jeopardy, and an alternate source must be located before any further economic consideration can be made.

7. The results of a corrosion study were not conclusive for a producing environment since most of the materials tested were not in a realistic producing environment.

Gulf should be recognized for several innovative techniques and enhancement of existing techniques.

1. Using a nonproducing minitest greatly expedited the time involved in initiating and carrying out the project. The actual field operations of the test took less than 10 months.

2. Time-lapse logging has been used extensively in the past, but Gulf added the triangulation method of evaluating oil, water, and gas saturations. While we had difficulty in reproducing the gas saturations due to the small margin for error, the method has definite potential for further development.

3. The heavy use of reservoir simulation and their history matching capabilities again demonstrated the use of computers in analyzing complex reservoir problems.

4. The project was carried out as a well-prepared operation. There were minimal equipment problems, and none adversely affected the outcome of the project.

Project Improvement

The primary suggestion for improvement in this project is that of project documentation. This was especially evident in difficulties encountered in our log analysis efforts. Library tape listings of log data were either inconsistent or missing, and incomplete information records were provided on log tapes. However, it should be noted that Gulf personnel were quite willing to provide assistance in sorting through this data. As noted above, several documentation inconsistencies were noted in the use of the triangulation technique for log analysis and in the actual sigma data to be used in this analysis. In addition, inconsistencies in simulation documentation and results were noted.

An addition of water-oil and gas-oil ratio data would have provided another tool for confirming saturation estimates. It is thought that such data could have been recorded during sampling operations. Careful measurements of gas volumes used in gas-lift operations would have been required for gas-oil ratios to be useful. The addition of Compensated Neutron log data would have enabled a confirming calculation to support the triangulation calculation technique for estimating CO_2 saturations.

Future Research

The time saving to be realized from a logging-observation well pilot versus an oil-in-the-tank pilot is significant. Although these results encourage expansion of the process to the Little Knife Field, the ability of these results to predict larger scale performance will not be established conclusively until a commercial scale or a larger scale test is performed. It is hoped that a CO_2 source will be secured which will enable a larger scale producing test to be performed in the Little Knife Field.

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TABLE 1

DESCRIPTION OF MINITEST AREA

Well Name	Location (feet)	Perforated Interval (feet)	Distance From Injection (feet)	Azimuth Angle (degree)
Zabolotny Injection Well No. 1	1,800 FNL & 2,460 FWL	9,824 - 9,839	--	--
Zabolotny Observation Well No. 1	1,500 FNL & 2,672 FWL	9,809 - 9,824	258	0
Zabolotny Observation Well No. 2	2,100 FNL & 2,460 FWL	9,855 - 9,871	250	201
Zabolotny Observation Well No. 3	1,800 FNL & 2,160 FWL	9,837 - 9,852	283	78.9
Zabolotny Observation Well No. 4	--	--	136	196.7
Zabolotny 4-3-1A	--	--	2,015	90
Zabolotny 1-3-4A	--	--	1,915	180
Zabolotny 2-3-3A	--	--	1,713	270

Source: Reference 1, Figures 5, 10, 12, and 14, and Table 27.

TABLE 2

BASIC RESERVOIR CHARACTERISTICS
ZONE D OF THE MISSION CANYON FORMATION
LITTLE KNIFE FIELD

Reservoir Depth, feet	9,800
Thickness, feet	16
Porosity, percent	21
Core Permeability, md	30
Interstitial Water Saturation, percent	21
Waterflood Residual Oil Saturation, percent	40
Reservoir Temperature, °F	245
Initial Reservoir Pressure, psia	4,409
Botton Hole Pressure, Dec. 1980, psia	3,345
Rock Compressibility, $psia^{-1}$	2.63×10^{-6}
Dip Angle, degree	0.5

Source: Reference 1, Table 25

TABLE 3

PHYSICAL PROPERTIES OF LITTLE KNIFE FIELD
RESERVOIR FLUIDS FROM
ZABOLOTNY 1-3-4A WELL

Reservoir Temperature, °F	245
Saturation Pressure (P_s), psia	2,698
Solution GOR at P_s, SCF/STB	1,119.4
Oil Formation Volume Factor at P_s, RB/STB	1.769
Oil Viscosity at P_s, cp	0.20
Oil Gravity, °API	41.0
Oil Density at Ps, gm/ml	0.6043
Oil Compressibility at P_s, psi^{-1}	28.95×10^{-6}
Minimum Miscibility Pressure with CO_2, psig	3,400
Water Formation Volume Factor, RB/STB	1.045
Water Viscosity, cp	0.456
Water Compressibility, psi^{-1}	3.89×10^{-6}

Source: Reference 1, Table 26

TABLE 4

PHYSICAL PROPERTIES AND ANALYSIS OF RESERVOIR FLUID FROM ZABOLOTNY 1-3-4A WELL

Saturation Pressure	2,698 psia
Coefficient of thermal expansion at 4,000 psia from 69°F to 245°F	7.2×10^{-4} vol/vol/°F
Density of oil at 2,698 psia and 245°F	0.6043 g/ml
Specific volume at 2,698 psia and 245°F	0.0265 cu. ft./lb.

HYDROCARBON ANALYSIS

Component	Mole, Percent	Volume, Percent
Nitrogen	0.91	0.27
Carbon Dioxide	1.21	0.51
Hydrogen Sulfide	5.73	2.09
Methane	33.34	15.03
Ethane	9.85	7.01
Propane	6.66	4.88
iso-Butane	1.35	1.18
n-Butane	3.85	3.24
iso-Pentane	1.49	1.45
n-Pentane	1.96	1.89
Hexanes	3.42	3.74
Heptanes-Plus	30.32	58.71
Total	100.00	100.00

Properties of Heptanes-plus Fraction

Sp. Gr. (60/60)	0.8390
API Gravity	37.2
Molecular Weight	192

Source: Reference 1, Table 33

TABLE 5

PULSE TEST RESULTS

	Two-Well Pulse Test Observation Well #1	Four-Well Pulse Test Observation Well Number #1	#2	#3	Average*
Distance from Injector, ft	258	258	250	283	263.7
Response Time, minutes	175.8	175.0	175.98	217.5	189.6
Maximum Amplitude, psi	17.60	21.18	15.835	16.01	17.078
Transmissibility, md-ft/cp	3,587.0	3,482.5	4,712.0	3,189.6	3,812.1
Diffusivity, 10^6 md-psi/cp	40.703	39.578	37.638	32.054	36.611
Storage Capacity, 10^{-6} ft/psi	88.138	87.990	125.19	99.507	104.25
Effective Permeability, md	27.2	29.3	27.4	23.0	26.2
Effective Hydraulic Thickness, ft	26.0	25.2	36.5	29.4	30.5
Storage, Rbbl/ac	34,290	33,610	47,820	38,010	39,927
Effective Pore Volume, Rbbl/ac-ft	1,318.8	1,333.7	1,310.1	1,293.8	1,310.0

* Average of Observation Well No. 1 test was used with Well Nos. 2 and 3 to compute overall average.

Source: Reference 1, 6, and 7

TABLE 6

RESERVOIR ROCK PROPERTIES INPUT DATA

Well Pair	Distance, Feet	Layers	Thickness, Feet	Porosity, Percent	Permeability, md k_h	Permeability, md k_v	Saturation Fraction PV S_{oi}	Saturation Fraction PV S_{orw}
Z1-Z01	258	W	10	0.105	4.2	3.0	0.680	0.55
		X	3	0.180	34.0	3.0	0.796	0.45
		Y	8	0.223	112.0	3.0	0.844	0.41
		Z	4	0.149	14.2	1.0	0.729	0.60
		XYZ*	15	0.195	50.1	3.0	0.811	0.46
Z1-Z02	250	W	20	0.112	5.0	3.0	0.680	0.55
		X	2	0.196	50.3	3.0	0.748	0.45
		Y	9	0.240	180.0	3.0	0.782	0.33
		Z	5	0.149	14.2	1.0	0.749	0.55
		XYZ*	16	0.206	70.0	3.0	0.770	0.40
Z1-Z03	283	W	15	0.100	3.6	3.0	0.680	0.55
		X	3	0.178	32.0	3.0	0.768	0.45
		Y	9	0.221	105.0	3.0	0.798	0.37
		Z	4	0.149	14.2	1.0	0.719	0.50
		XYZ*	16	0.195	50.1	3.0	0.778	0.41
Average**		W	15.0	0.106	4.3	3.0	0.680	0.55
		X	3.0	0.184	38.8	3.0	0.771	0.45
		Y	8.5	0.228	132.3	3.0	0.808	0.38
		Z	4.5	0.149	14.2	1.0	0.732	0.55

* For 11x11x2 grid system
** For 16x15x4 grid system

Source: Reference 1, Table 28

TABLE 7

WELL PRODUCTIVITY INDEX AND PRODUCTION ALLOCATION FACTORS USED IN LITTLE KNIFE MINITEST WATER INJECTION SIMULATION

Well Name	kh Allocation Factor	Productivity Index (STB/D/PSI)	Constant Bottom Hole Flowing Pressure (psig)
Sabrosky 2-31-3C	.299	.064052	2,000.
Zabolotny 4-3-1A	.152	.034657	2,000.
G. Hurinenko	.901	.287144	2,000.
Zabolotny 1-3-4A	1.000	.283083	2,000.
Zabolotny 2-3-3A	.765	.203704	2,000.
Hurinenko 2-10-1A	.865	.170610	2,000.
Hurinenko 1-10-2A	.692	.129919	2,000.
Miller 3-10-4B	.109	Shut in (3/1/79)	2,000.
Zabolotny Injection No. 1		1.500000*	700.**

* Injectivity for Zabolotny Injection Well No. 1
** Surface tubing pressure restriction

Source: Reference 4, Tables 8 and 10

TABLE 8

PRESSURE SUMMARY OF PREDICTION CASE RESULTS
LITTLE KNIFE MINITEST WATER INJECTION SIMULATION

Prediction Case Number	Date	Total Producing Rate (STB/D)	Volumetric Average Reservoir Pressure At Cell Depth (psia)	Minitest Area Average Pressure At Cell Depth (psia)
1	10/15/80	1,445	3,776	3,359
2	10/15/80	1,465	3,781	3,717
3	10/15/80	1,733	3,760	3,315
4	10/15/80	1,733	3,765	3,684
5	09/15/80	1,733	3,791	3,720

Source: Reference 4, Table 11

TABLE 9

FLUID INJECTION SCHEDULE

Phase	Dates	Days	Fluids Injected At Surface Conditions	Fluids Injected At Reservoir Conditions (Rbbls)	Hydrocarbon Pore Volume Percentage
Initial	12/11/80-1/7/81	27	29,539 bbls	30,721	29.26
1st CO_2	1/7/81-1/24/81	17	420 tons	4,477	4.26
Water	1/24/81-1/27/81	3	5,007 bbls	5,207	4.95
2nd CO_2	1/27/81-2/5/81	9	420 tons	4,477	4.26
Water	2/5/81-2/9/81	4	4,964 bbls	5,163	4.92
3rd CO_2	2/9/81-2/26/81	17	432 tons	4,605	4.39
Water	2/26/81-3/2/81	4	4,874 bbls	5,069	4.83
4th CO_2	3/2/81-3/11/81	9	403 tons	4,296	4.09
Water	3/11/81-3/16/81	5	5,776 bbls	6,007	5.72
5th CO_2	3/16/81-3/25/81	9	419 tons	4,467	4.25
Flush Water	3/25/81-9/24/81	182	198,794 bbls	206,746	196.9
Total Water	12/11/80-7/24/81	225	248,954 bbls	258,912	246.6
Total CO_2	11/7/81-3/25/81	61	2,094 tons	22,322	21.25

Source: References 1 and 22

TABLE 10

PATTERN AREA VOLUMETRIC DATA

Radius = 283 feet

Layer	Thickness, Feet	Porosity, Percent	Pore Volume, bbls	Soi	HCPV*, bbl
W	15.0	0.106	71,200	0.680	48,400
X	3.0	0.184	24,700	0.778	19,200
Y	8.5	0.228	86.800	0.810	70,300
Z	4.5	0.149	30,000	0.724	21,700
XYZ	16.0	0.198	141,500	0.786	111,200
WXYZ	31.0	-	212,700	-	159,600

* HCPV = Hydrocarbon Pore Volume

Source: Reference 23, Table 4

TABLE 11

COMPARISON OF WATER SATURATION IN FINAL TIME LAPSE LOGGING RESULTS

	Observation Well No. 1	2	3	Average
For Layer W				
PETROS, Percent	46.4	34.9	59.5	44.2
Gulflog, Percent	47.0	33.0	56.4	43.0
Net Pay, Feet	24.0	30.0	15.0	23.0
For Layer X				
PETROS, Percent	43.9	56.0	48.9	48.8
Gulflog, Percent	55.3	63.1	42.0	53.7
Net Pay, Feet	3.0	2.0	2.0	2.3
For Layer Y				
PETROS, Percent	59.5	68.9	55.0	61.1
Gulflog, Percent	59.8	74.8	66.1	68.9
Net Pay, Feet	9.0	9.0	9.0	9.0
For Layer Z				
PETROS, Percent	53.2	27.0	47.3	43.3
Gulflog, Percent	40.1	45.8	45.1	43.4
Net Pay, Feet	5.0	4.0	4.0	4.3
All Layers				
PETROS, Percent	49.9	41.9	55.8	48.3
Gulflog, Percent	49.6	43.8	56.8	49.2
Net Pay, Feet	41.0	45.0	30.0	38.7

TABLE 12

PERCENTAGES OF OIL DISPLACED
RADIUS = 283 FEET

Layer	OIP STB*	Oil Displaced, Percent OIP** Waterflood	CO_2/Water-1:1	Incremental
W	27,360	15	17	2
X	10,854	39	58	19
Y	39,740	57	79	22
Z	12,267	21	24	3
Total	90,221	37	50	13

* At stock tank conditions, for layers W, X, Y, and Z in the minitest area
** Oil-in-place on December 11, 1980

Source: Reference 1, Table 29

TABLE 13

OIL RECOVERIES FROM COMPOSITION SIMULATION

Case Number	Oil Recovery (STB) As A Percent Of the Oil-In-Place (OIP) On December 11, 1980		Incremental	Description of Results
	Waterflood	1:1 CO_2-Water		
1	37	50	13	Displaced in the Minitest Area from the entire project interval.
2	34 (35*)	45 (44*)	11 (9*)	Recovered from Observation Well Nos. 1, 2, and 3 if operated as producers - calculated by maintaining fluid production from the observation wells so as to match observed pressure history.
3	38.0 (38.9*)	48.3 (47.4*)	10.3 (8.5*)	Back calculating the results from Case No. 2 to a percentage of the Original Oil-In-Place (OOIP) at discovery conditions.
4	40	48	8	Commercial scale application based upon performance in one quadrant of a 160-acre five-spot pattern.

* Results provided in Reference 1, p. 51.

Source: Reference 23, pp. 7 and 8.

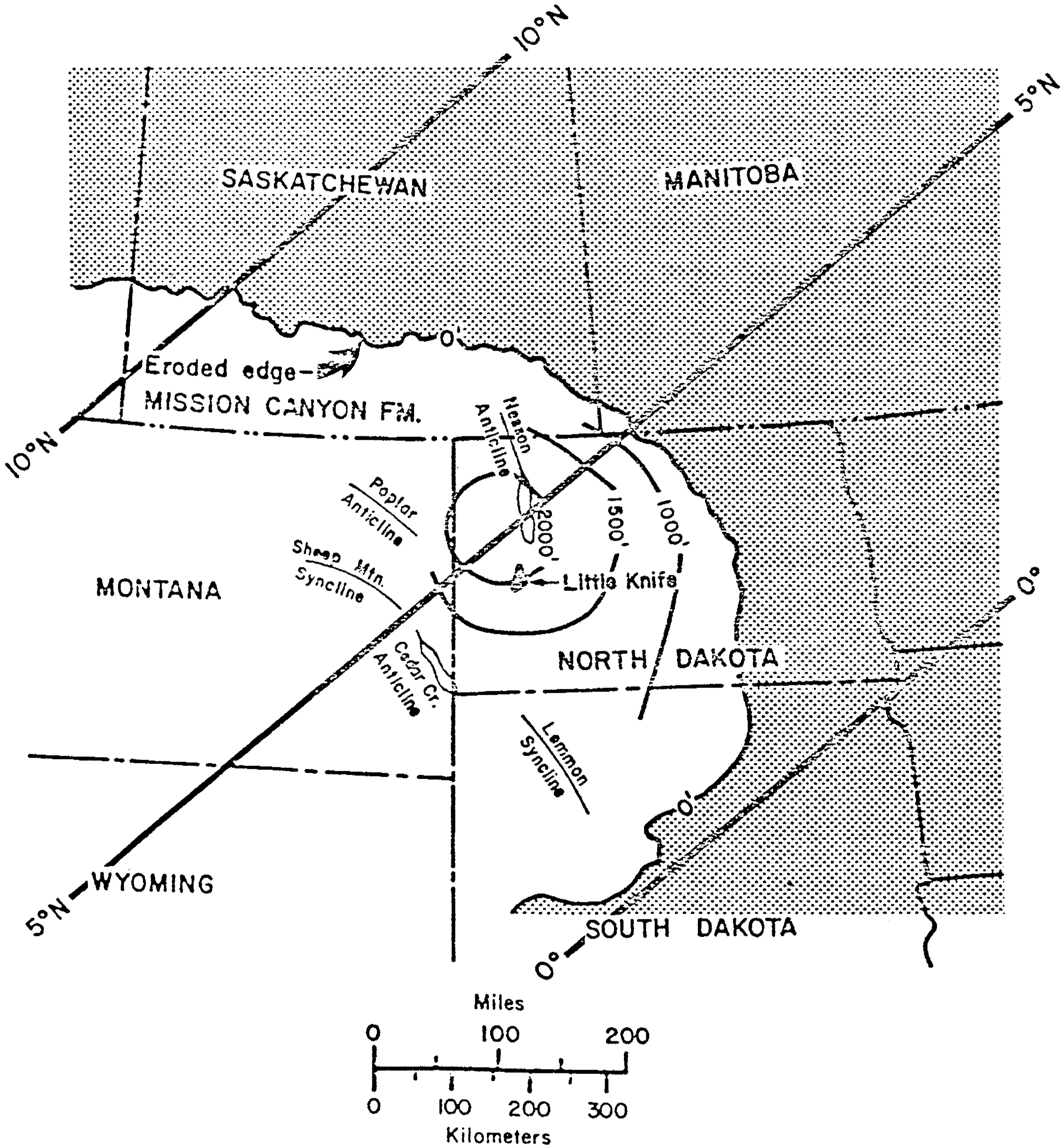
FIGURE 1

SIGNIFICANT EVENTS IN THE LITTLE KNIFE FIELD

```
                              1977            1978            1979            1980            1981                              1982            1983
Event                         JFMAMJJASOND    JFMAMJJASOND    JFMAMJJASOND    JFMAMJJASOND    J  F  M  A  M  J  J  A  S  OND    JFMAMJJASOND    JFMAMJJ

Field Discovery                X

Proposal for Minitest                                 X

Drilling and Completions
     Injection Well                                      X    X
     Observation Well No. 1                                   XX
     Observation Well No. 2                                      XX
     Observation Well No. 3                                         XX
     Observation Well No. 4                                                                               X-X

Multi-well Tests                                                 XX      X

Minitest Duration                                                         X-------------------------------------------X

Preflush Injection with an                                                X---X
     IPA Tracer

CO2 Injections (5 Phases)                                                                     11 2 33 4  5

WAG Injections (4 Phases)                                                                        1  2  3 4
     with a NPA Tracer

Drive Water Injection with                                                                                 X----------------------------------X
     No Tracers


Fluid Breakthrough for Obs.
     Wells 1, 2, & 3
------------------

     Isopropyl Alcohol IPA                                                                              1  2     3
     Carbon Dioxide CO2                                                                                  1      23
     Normal Propyl Alcohol NPA                                                                                   12 3

Multiple Internal Gulf                                                                                                                 X
     Studies Completed

Final Report Issued to DOE                                                                                                                            X
```

FIGURE 2

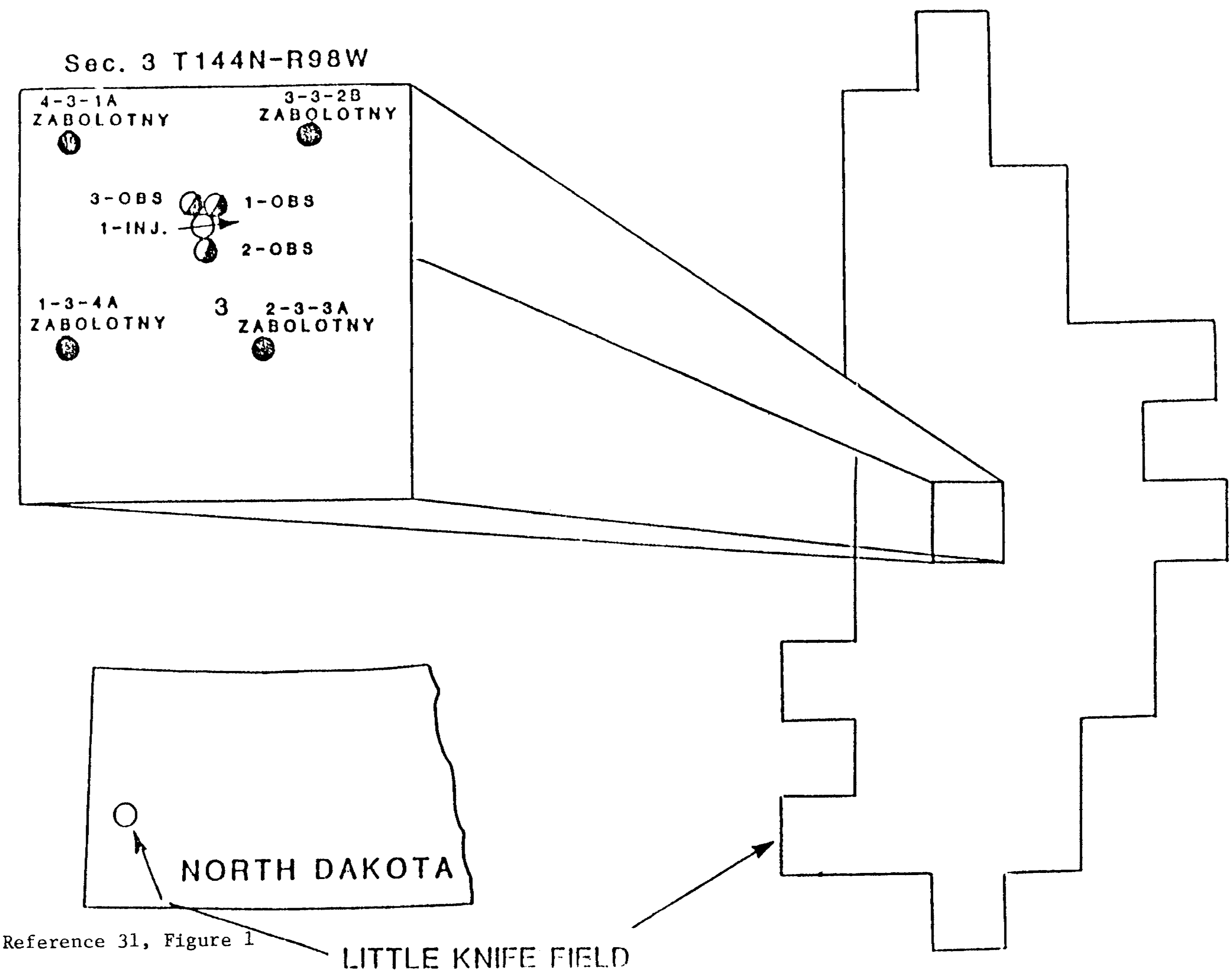
INDEX MAP OF WILLISTON BASIN



Source: Reference 1, Figure 1

FIGURE 3

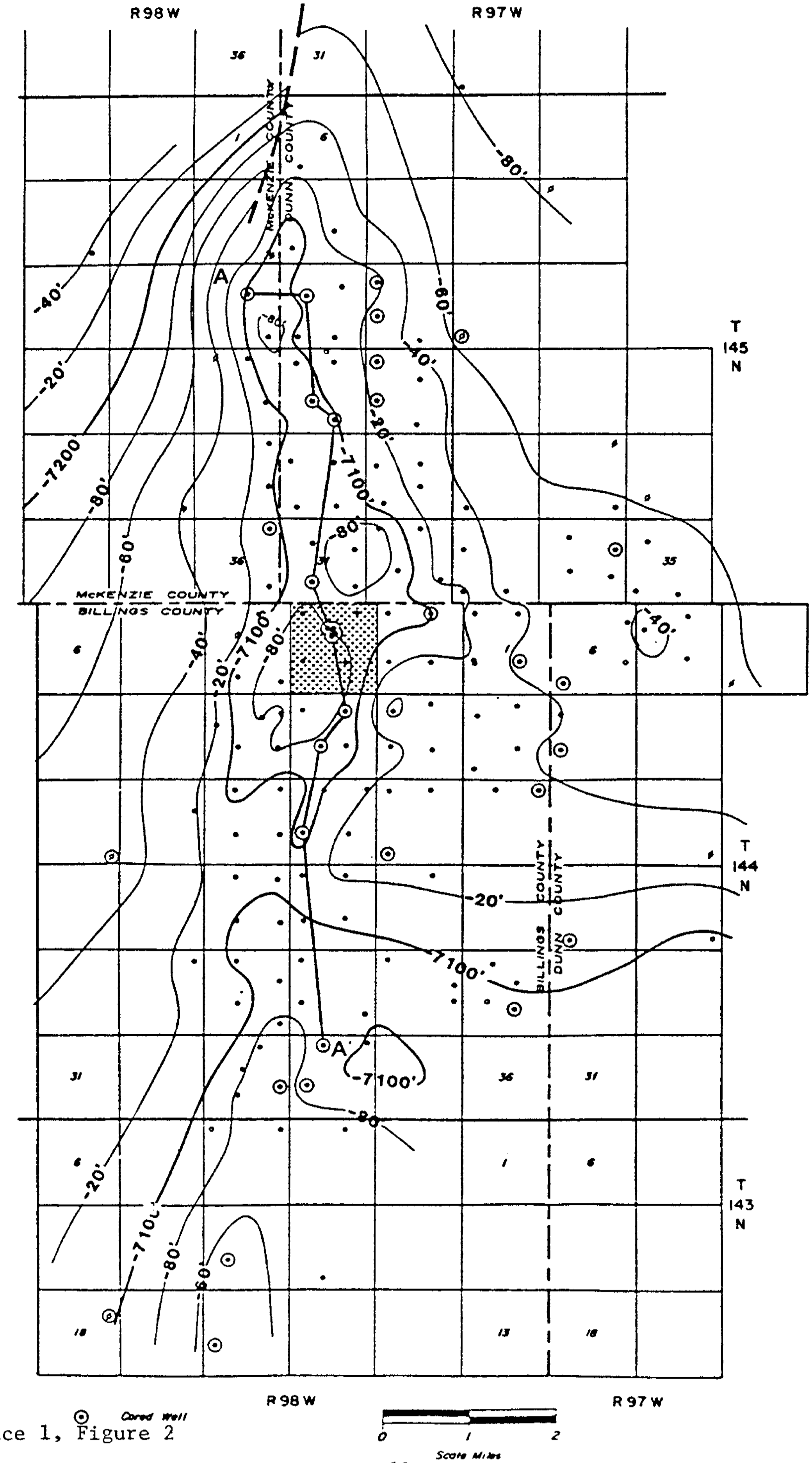
CO_2 MINITEST LOCATION IN THE LITTLE KNIFE FIELD, NORTH DAKOTA



Source: Reference 31, Figure 1

FIGURE 4

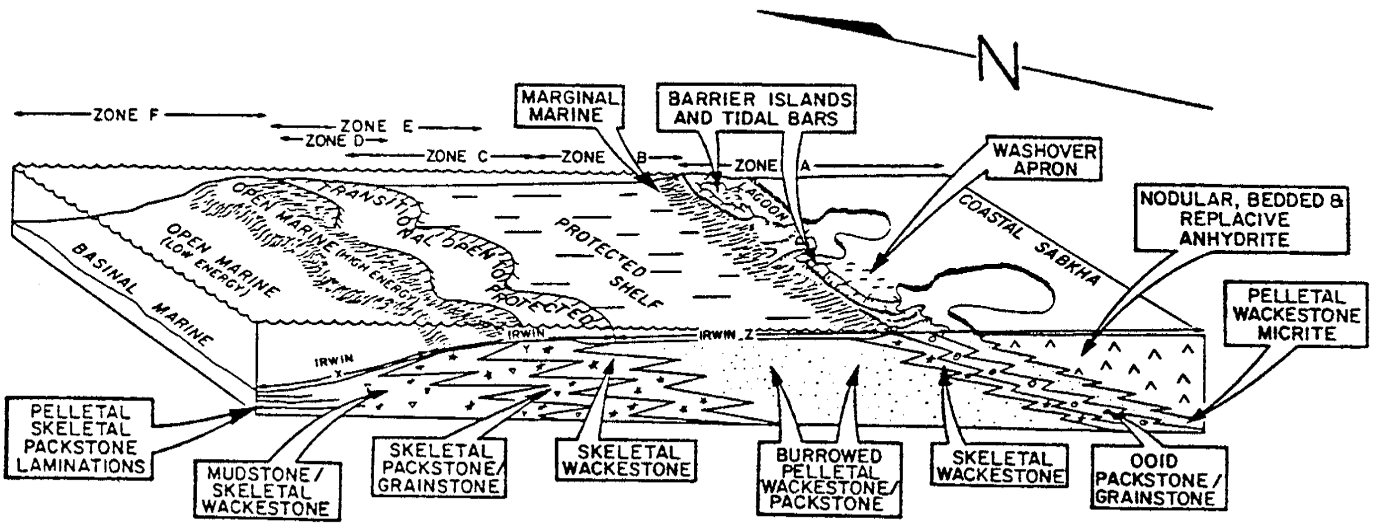
TOP OF MISSION CANYON FORMATION



Source: Reference 1, Figure 2

FIGURE 5

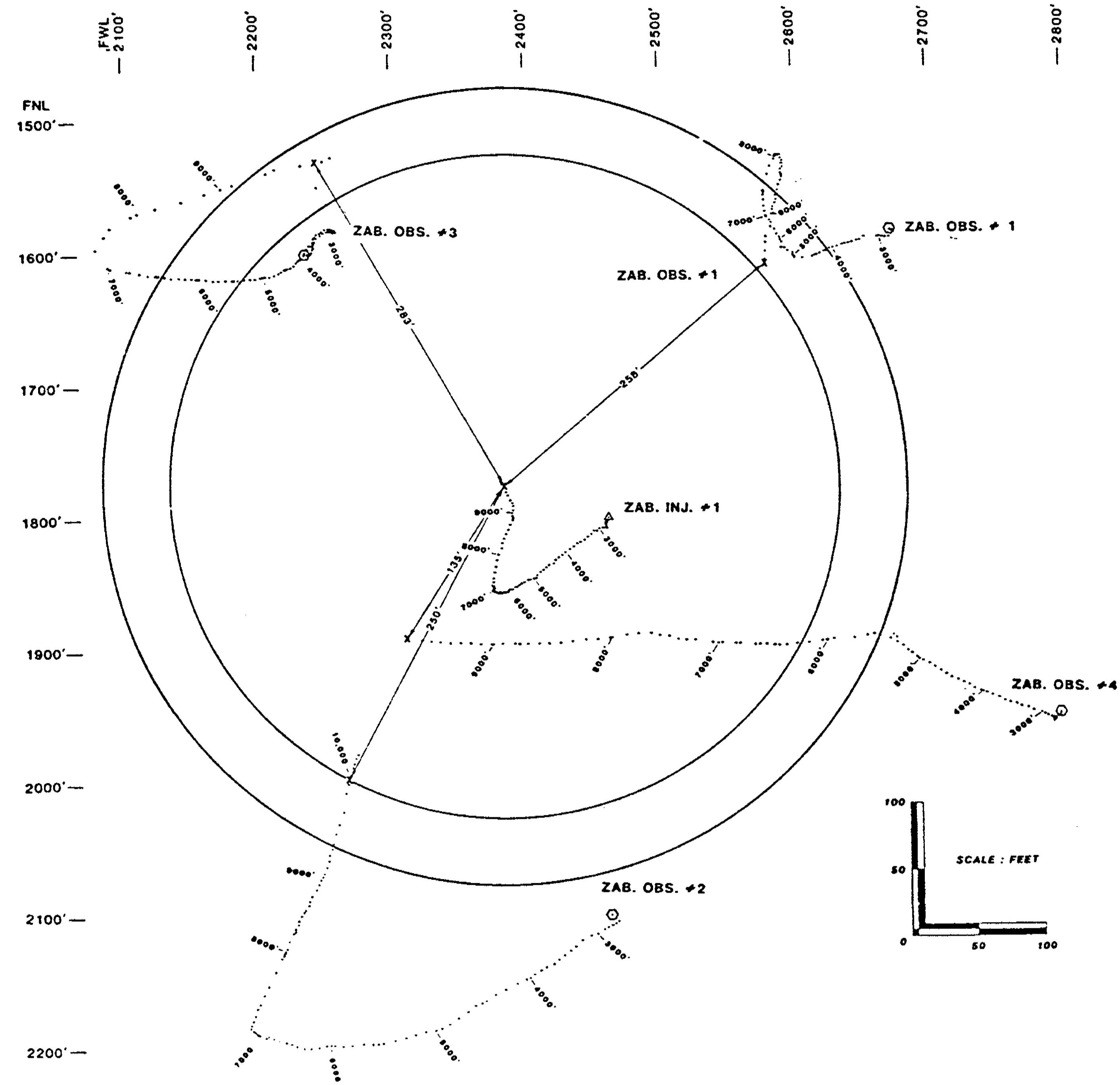
IDEALIZED DEPOSITIONAL SETTING FOR THE MISSION CANYON FORMATION AT LITTLE KNIFE FIELD



Source: Reference 3, Figure 5

FIGURE 6

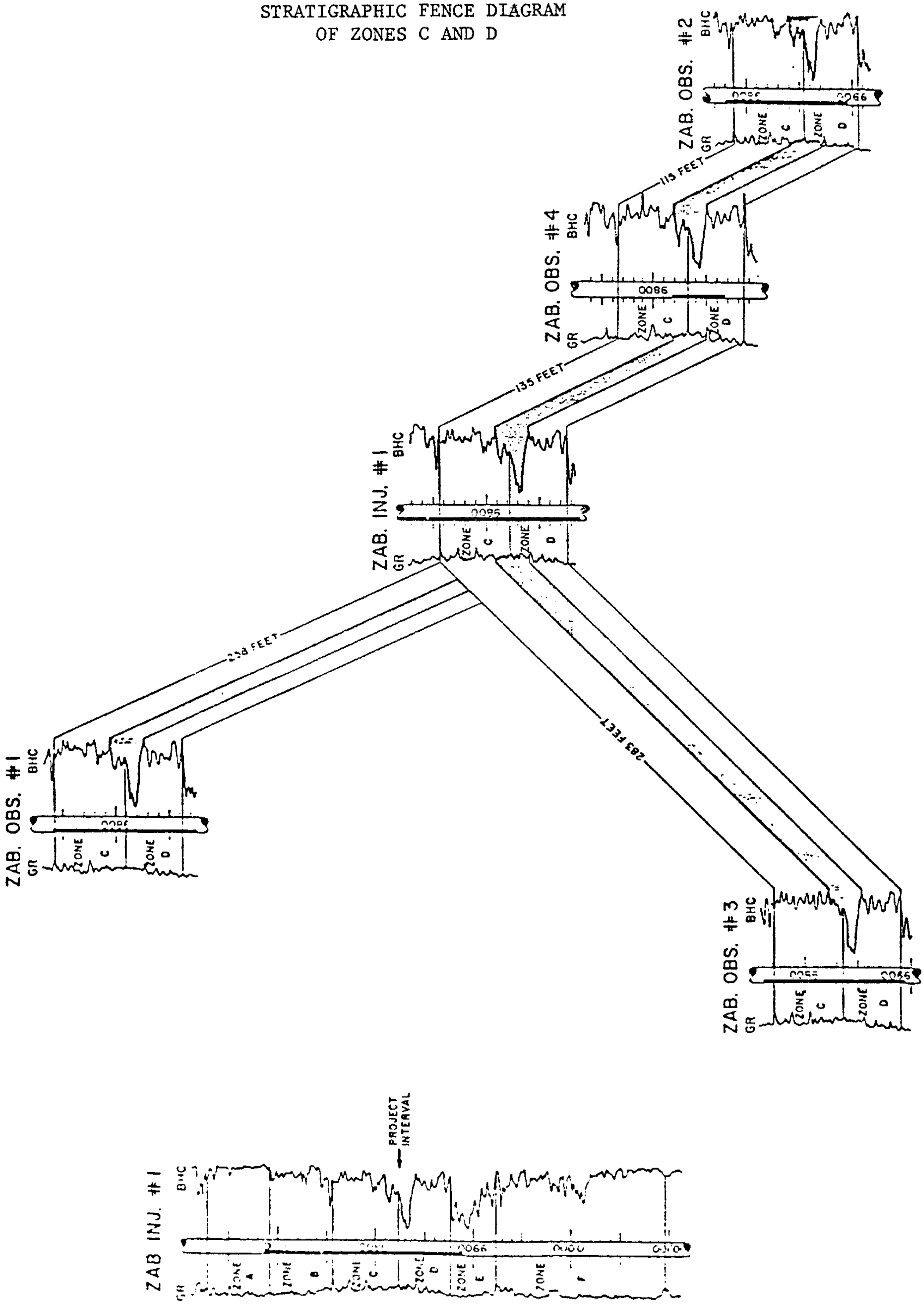
LITTLE KNIFE MINITEST PATTERN



Source: Reference 1, Figure 3

FIGURE 7

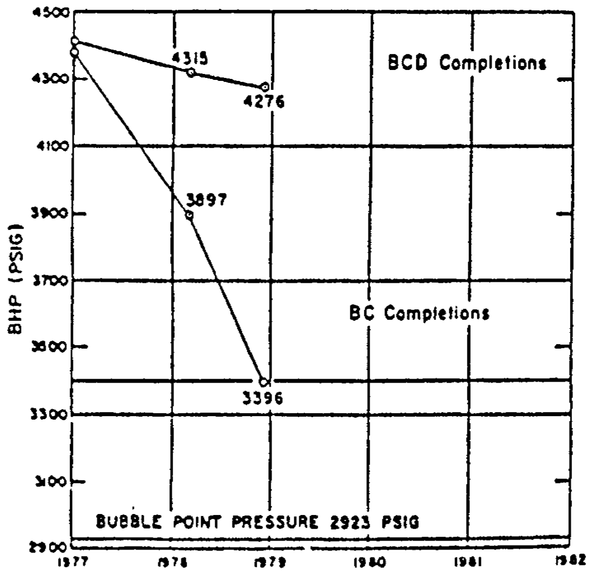
STRATIGRAPHIC FENCE DIAGRAM
OF ZONES C AND D



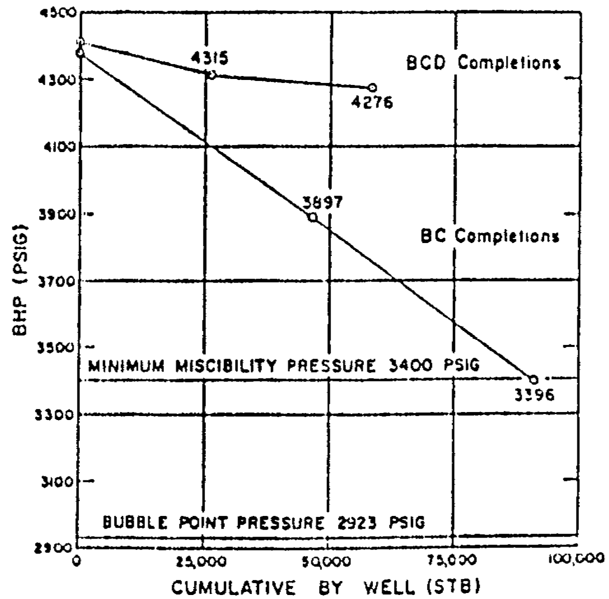
Source: Reference 1, Figure 38

FIGURE 8

MISSION CANYON FORMATION BHP HISTORY



Mission Canyon Fm. BHP vs. time.

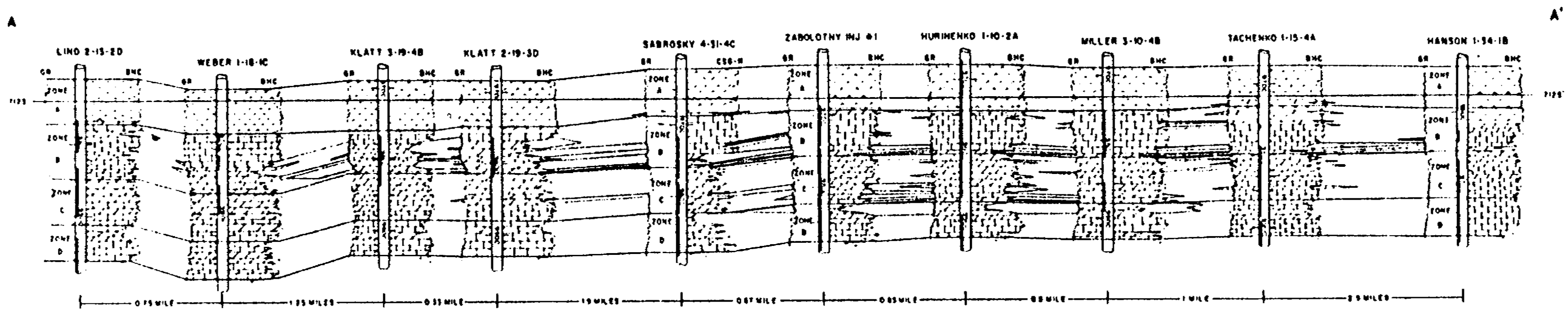


Mission Canyon Fm. BHP vs. cumulative production.

Source: Reference 5, Figures 5 and 6

FIGURE 9

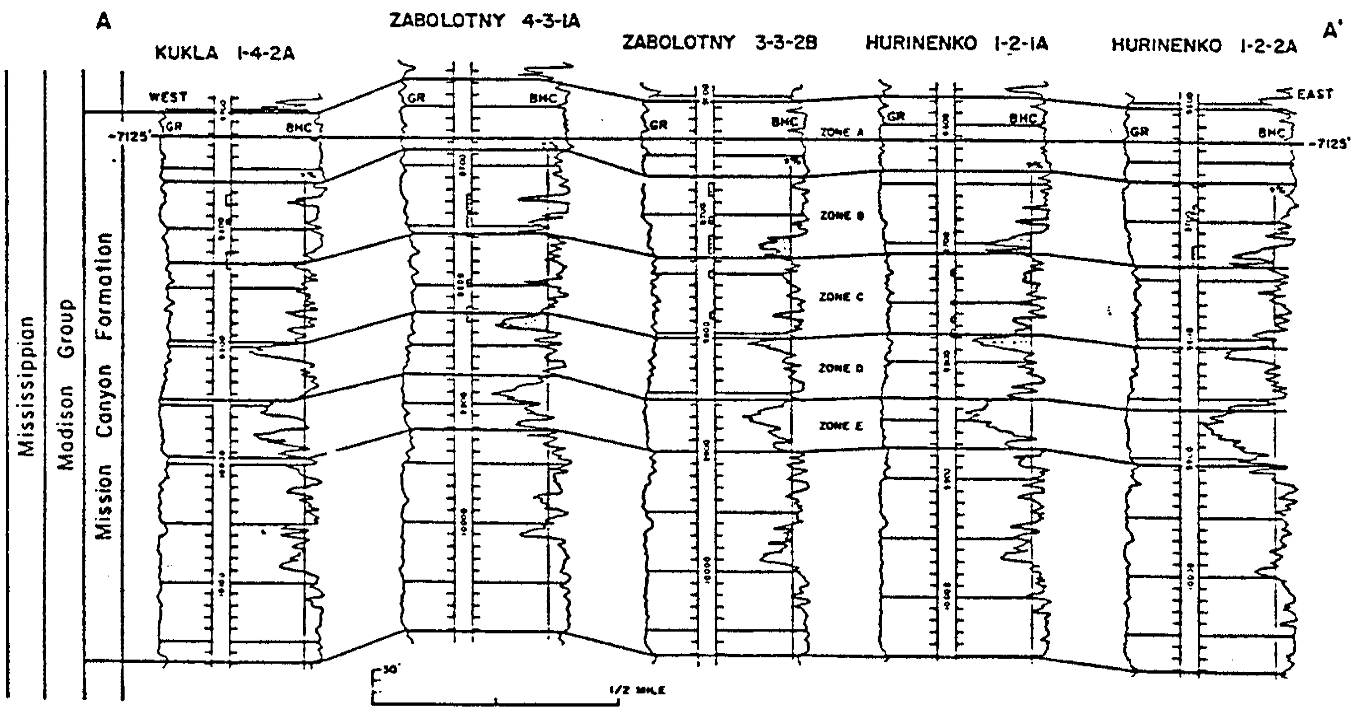
NORTH-SOUTH STRUCTURAL FENCE DIAGRAM



Source: Reference 1, Figure 31

FIGURE 10

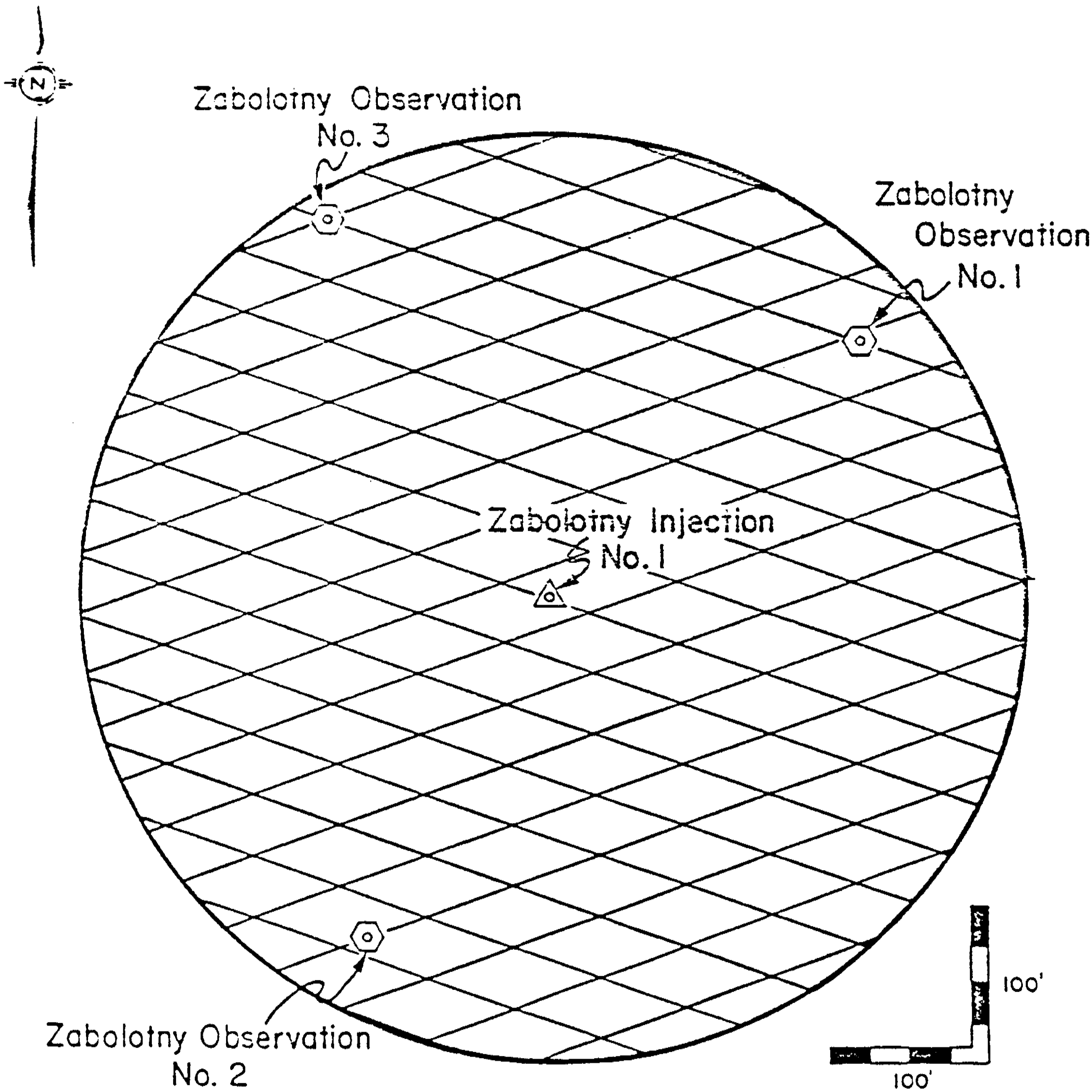
WEST TO EAST STRUCTURAL CROSS SECTION



Source: Reference 5 , Figure 13

FIGURE 11

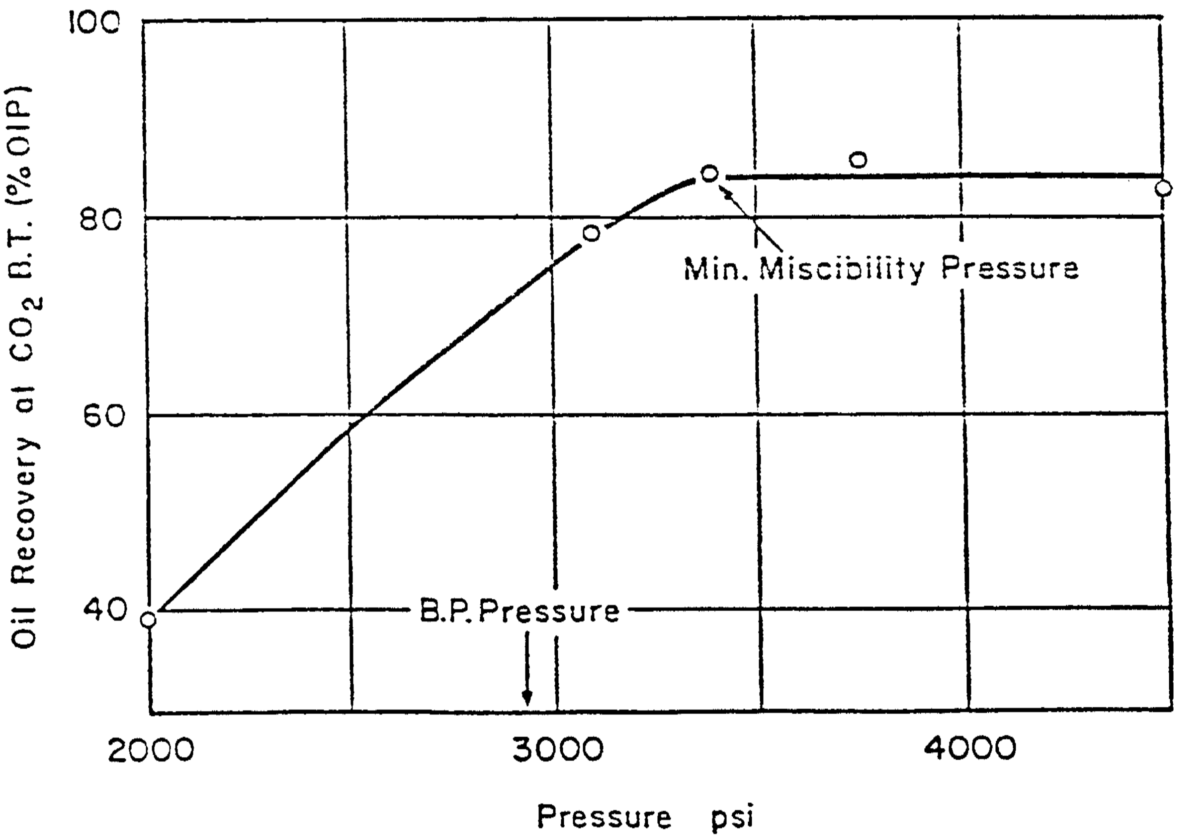
TYPICAL FRACTURE TRENDS



Source: Reference 1, Figure 52

FIGURE 12

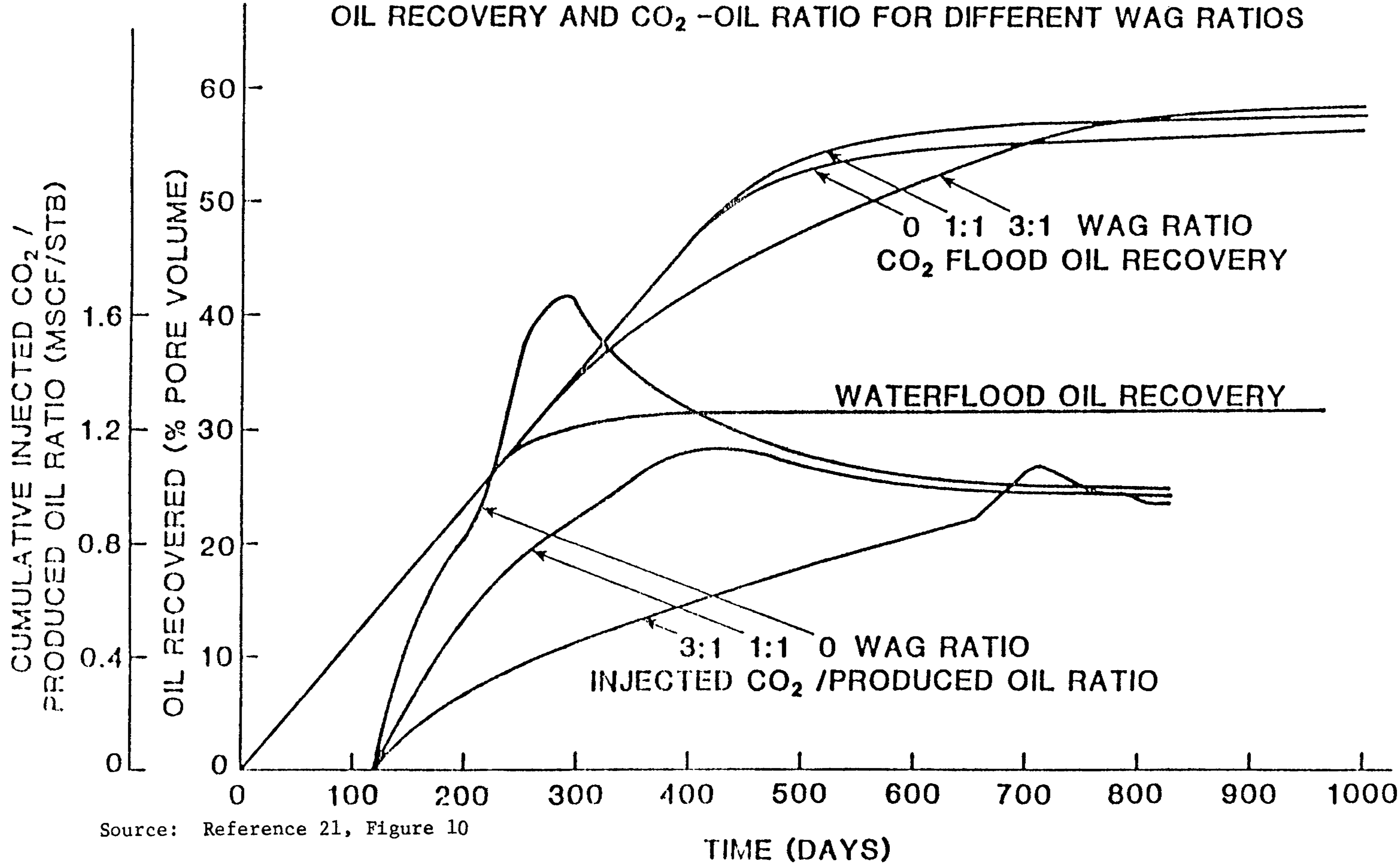
MMP TEST RESULTS



Source: Reference 2, Figure 6

FIGURE 13

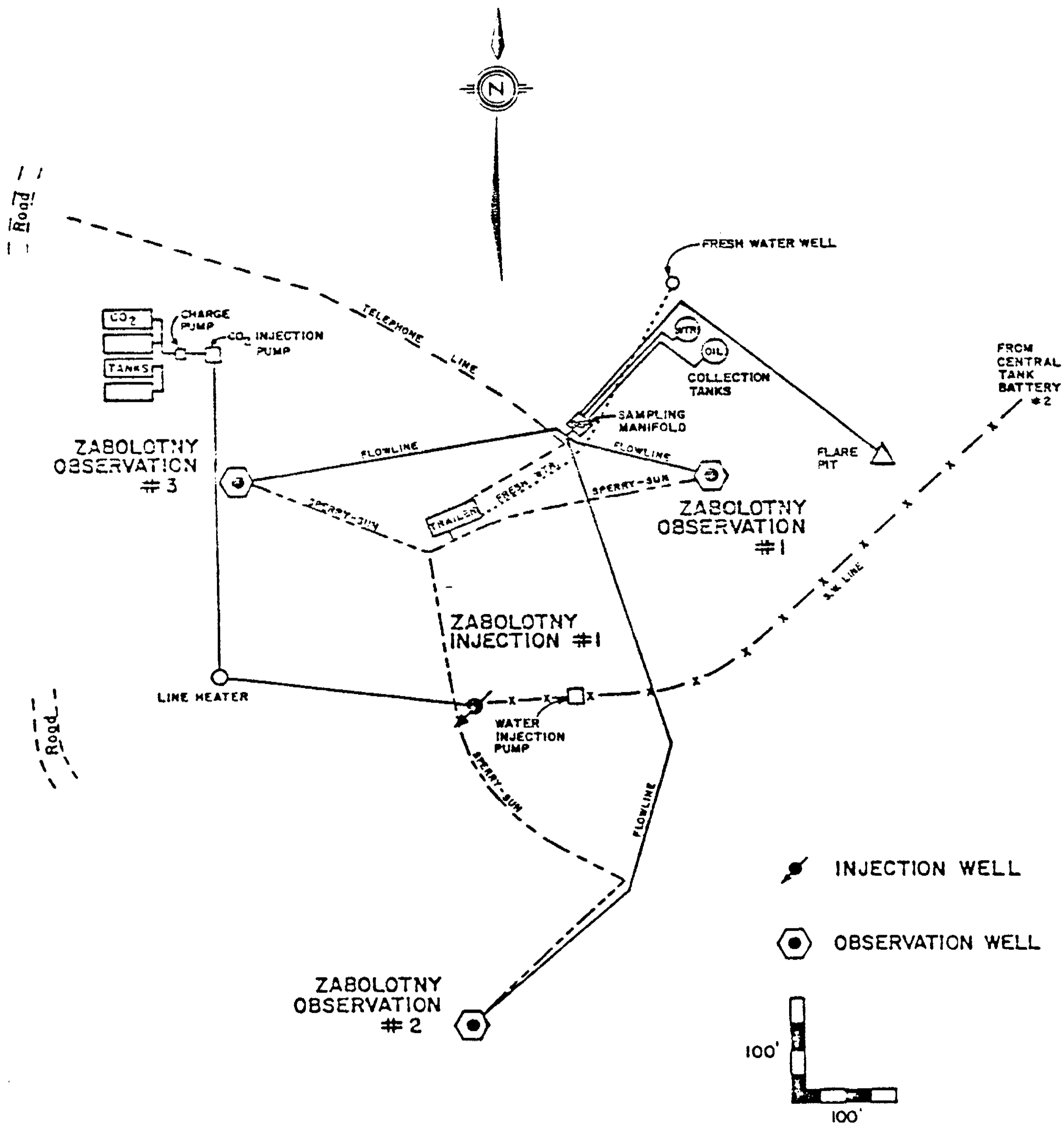
LITTLE KNIFE MINITEST CO_2 FLOOD SIMULATION
CROSS-SECTION OF ~ 1/3 OF 5-ACRE MISSION CANYON "D" ZONE —
OIL RECOVERY AND CO_2 -OIL RATIO FOR DIFFERENT WAG RATIOS



Source: Reference 21, Figure 10

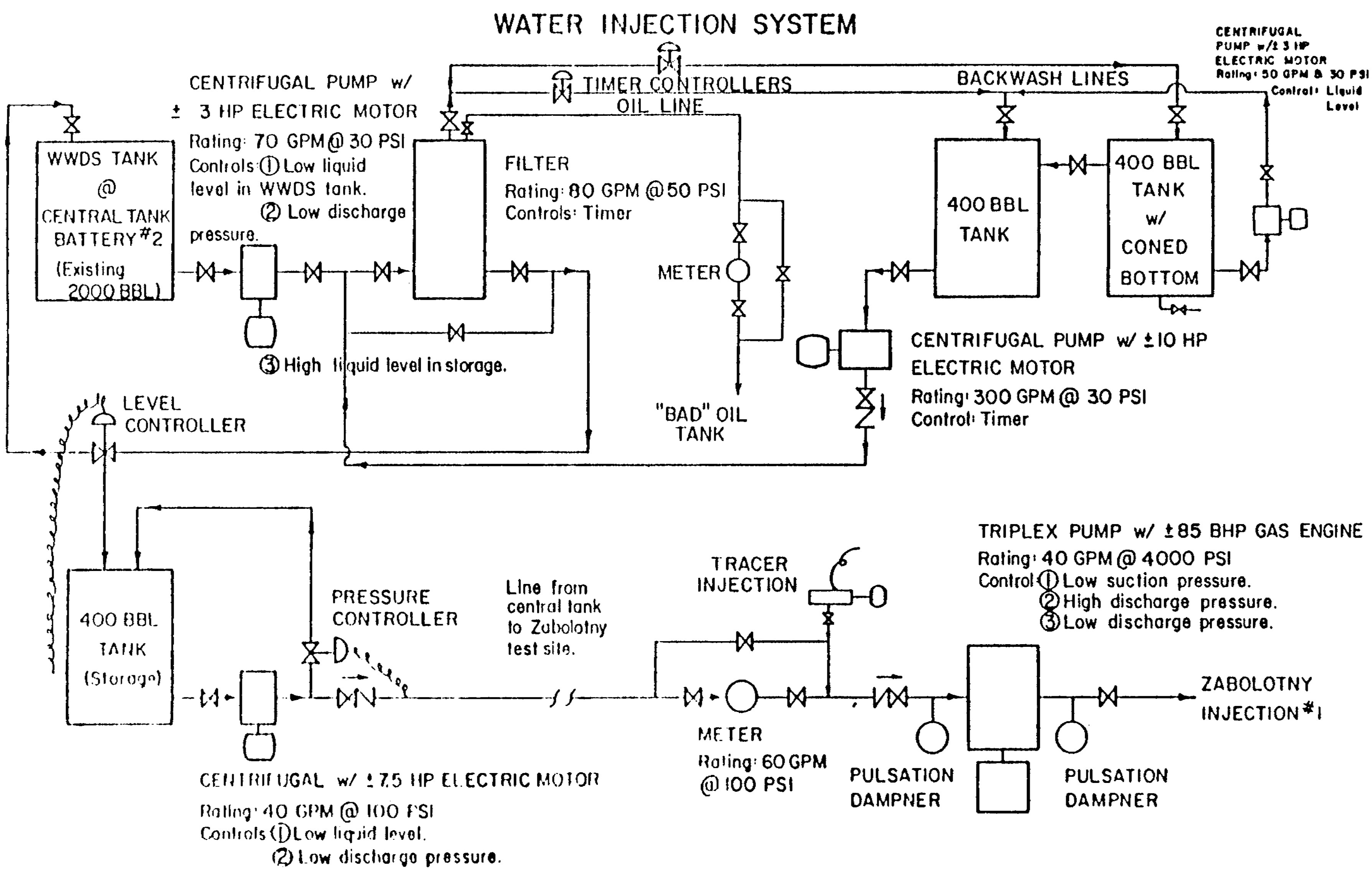
FIGURE 14

INJECTION FACILITIES



Source: Reference 1, Figure 68

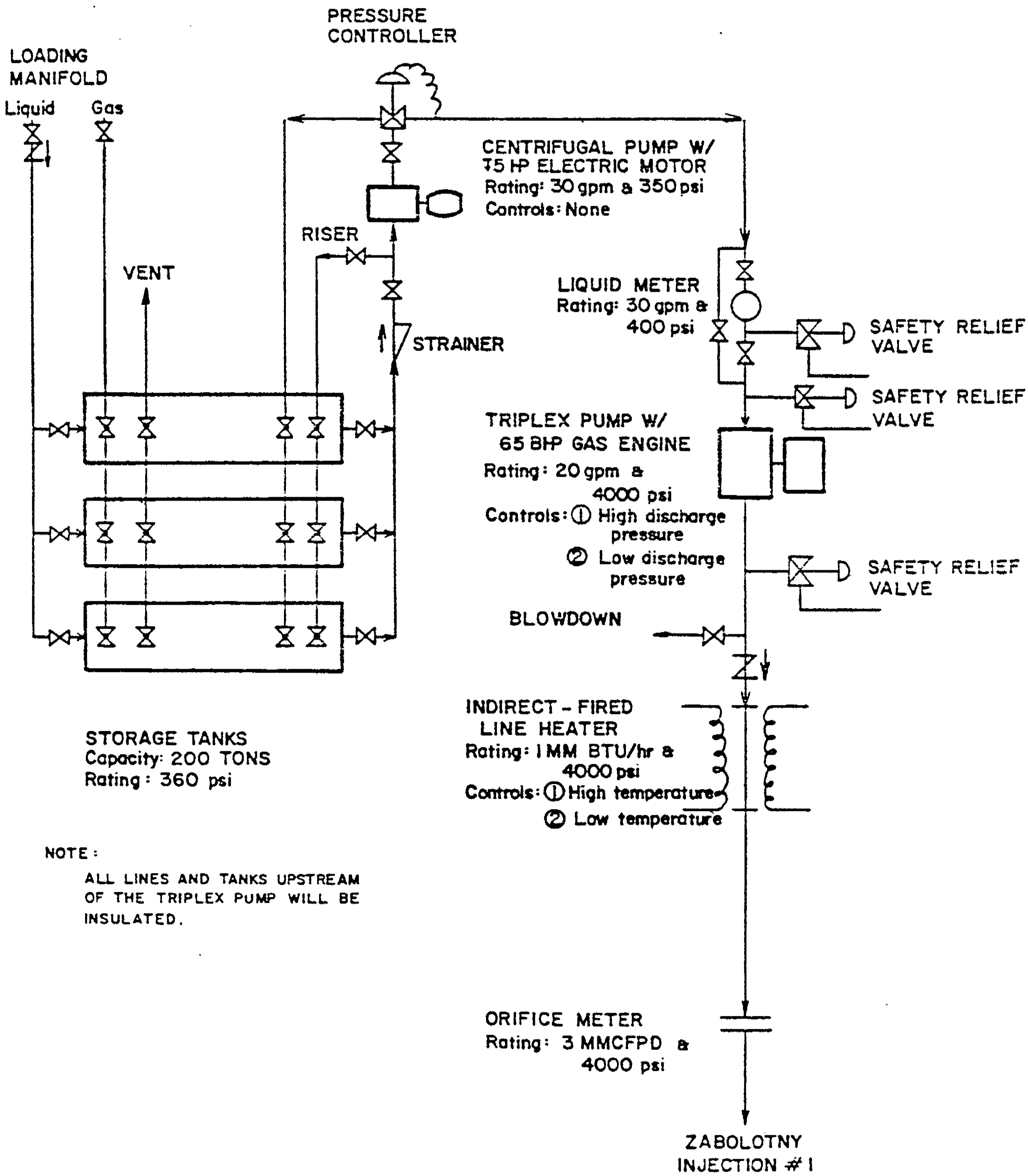
FIGURE 15



Source: Reference 1, Figure 75

FIGURE 16

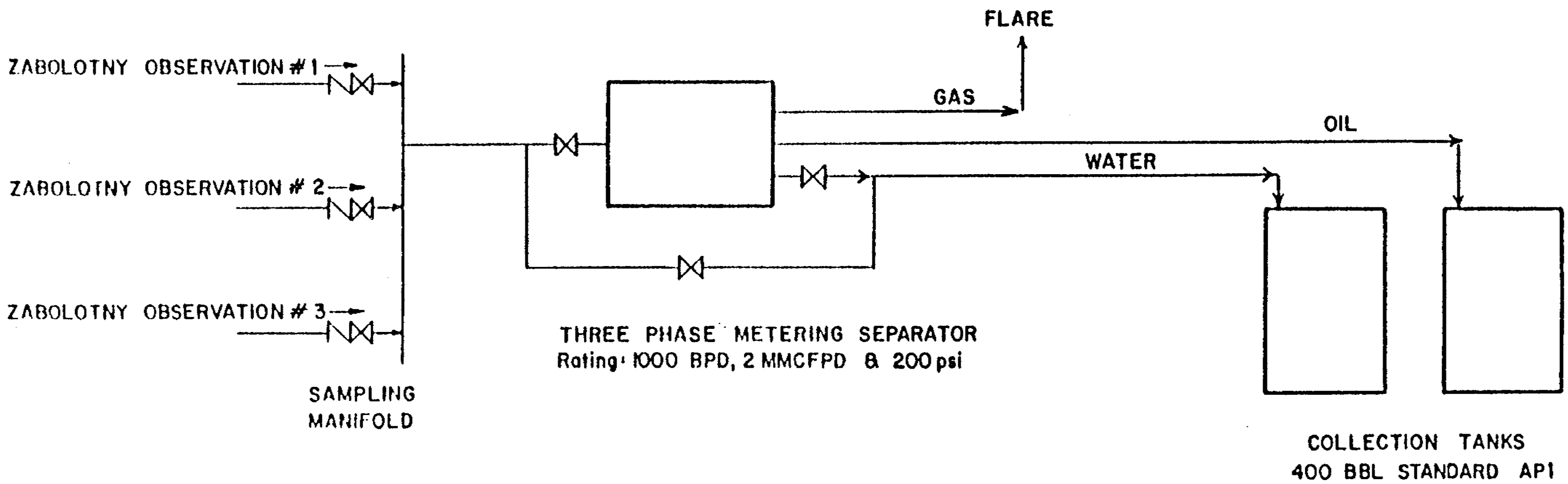
CARBON DIOXIDE INJECTION SYSTEM



Source: Reference 1, Figure 69

FIGURE 17

FLUID SAMPLING SYSTEM



Source: Reference 1, Figure 78

<u>FIGURE 18</u>

PETROS PETROPHYSICAL EVALUATION SYSTEM
LITTLE KNIFE, N.D.
ZABOLOTNY OBSERVATION NO:1

REMARKS:
TRACK 1: SIGMA FROM BASE, FIRST MONITOR, LAST MONITOR
TRACK 2: RATIO FROM BASE, FIRST MONITOR, LAST MONITOR, & POROSITY
TRACK 3: SW FROM BASE, FIRST MONITOR, LAST MONITOR
TRACK 4: BULK VOLUME BASE (7-17-80)
TRACK 5: BULK VOLUME FIRST MONITOR (3-9-81)
TRACK 6: BULK VOLUME LAST MONITOR (9-18-81)

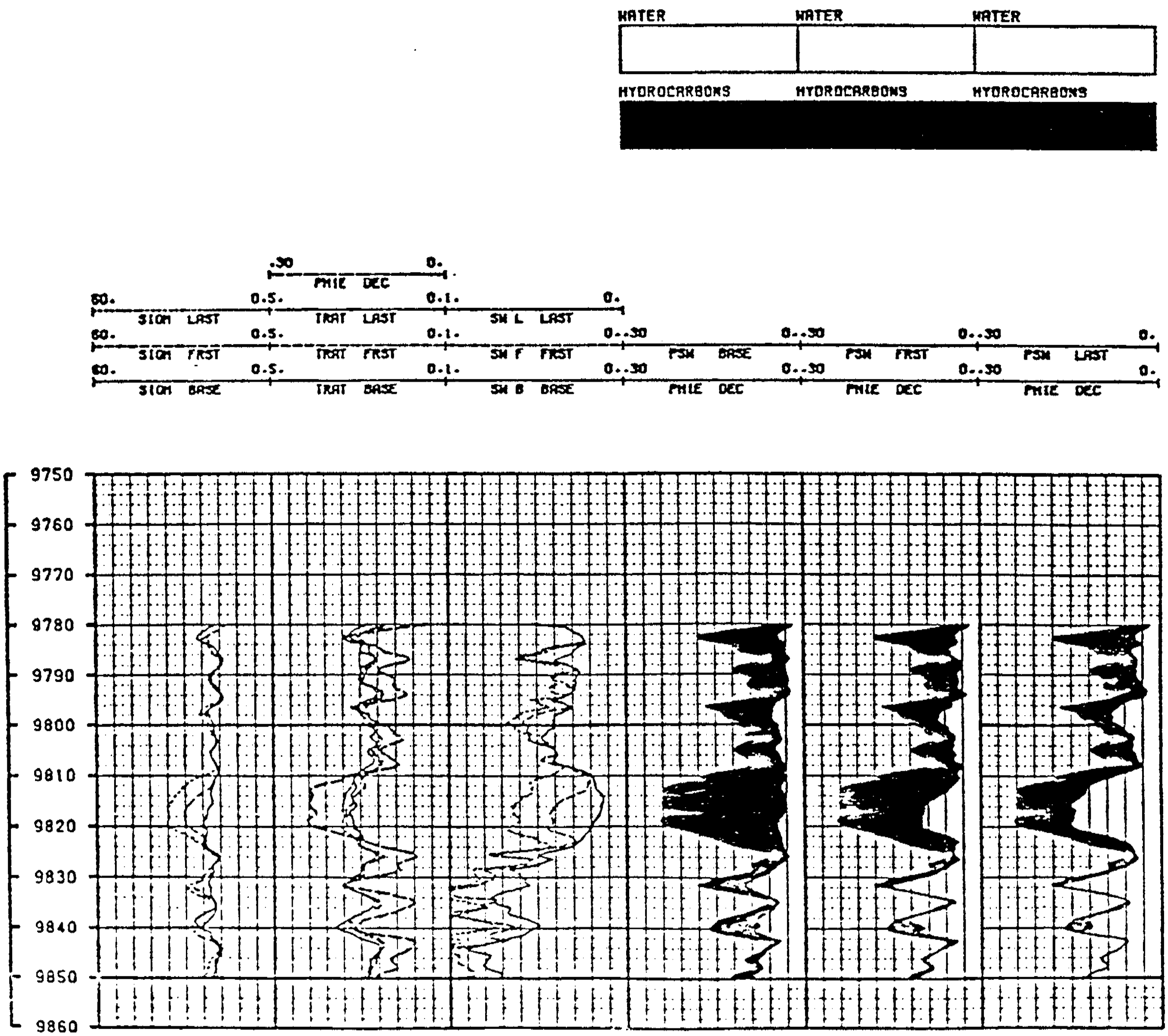


FIGURE 19

PETROS PETROPHYSICAL EVALUATION SYSTEM
LITTLE KNIFE.N.D.
ZABOLOTNY OBSERVATION NO:2

REMARKS:
TRACK 1: SIGMA FROM BASE. FIRST MONITOR. LAST MONITOR
TRACK 2: RATIO FROM BASE. FIRST MONITOR. LAST MONITOR. & POROSITY
TRACK 3: SW FROM BASE. FIRST MONITOR. LAST MONITOR
TRACK 4: BULK VOLUME BASE (12-04-80)
TRACK 5: BULK VOLUME FIRST MONITOR (3-20-81. 5-19-81 FOR W-LAYER)
TRACK 6: BULK VOLUME LAST MONITOR (9-18-81)

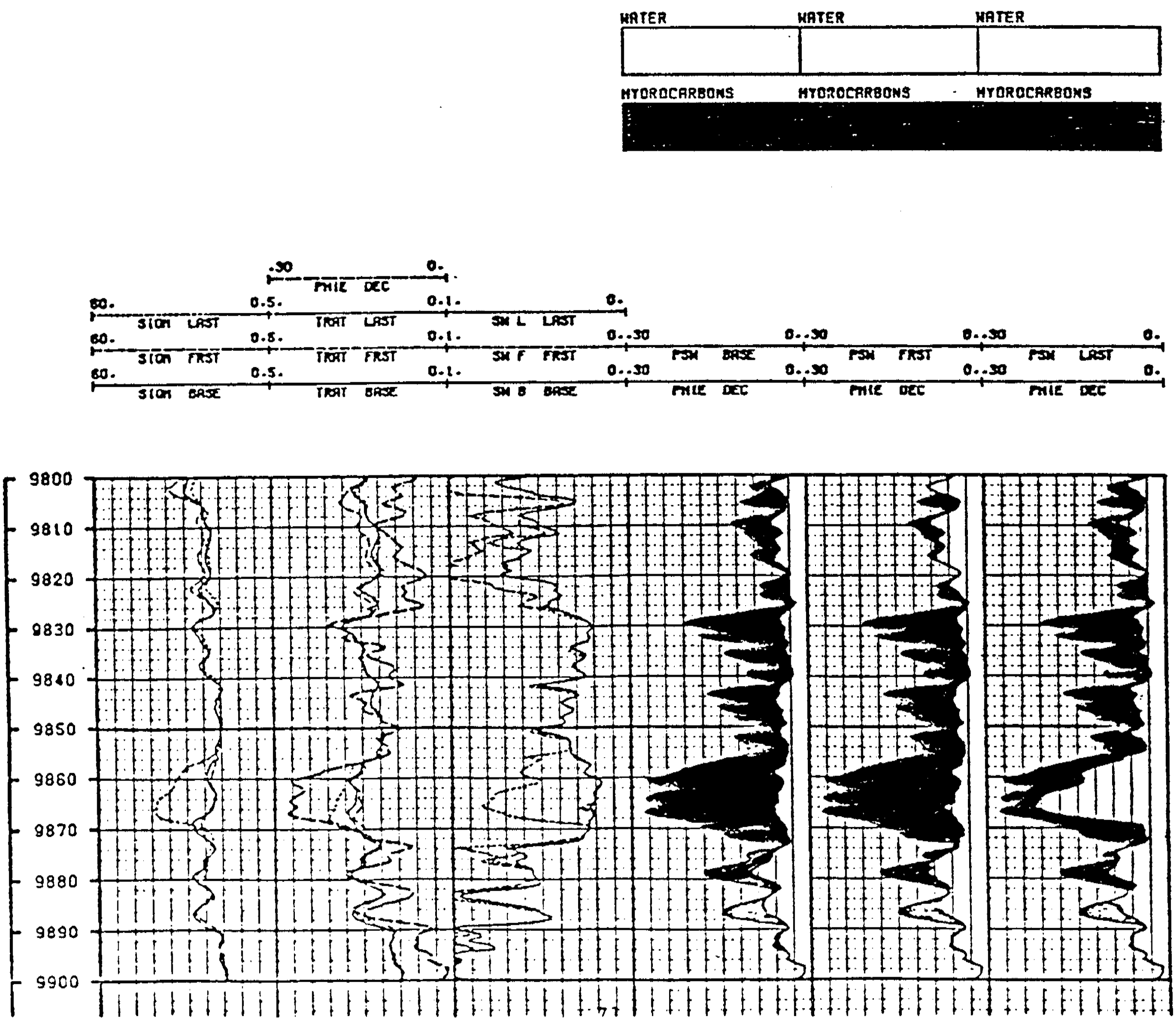


FIGURE 20

PETROS PETROPHYSICAL EVALUATION SYSTEM
LITTLE KNIFE,N.D.
ZABOLOTNY OBSERVATION NO:3

REMARKS:
TRACK 1: SIGMA FROM BASE, FIRST MONITOR, LAST MONITOR
TRACK 2: RATIO FROM BASE, FIRST MONITOR, LAST MONITOR, & POROSITY
TRACK 3: SW FROM BASE, FIRST MONITOR, LAST MONITOR
TRACK 4: BULK VOLUME BASE (12-03-80)
TRACK 5: BULK VOLUME FIRST MONITOR (5-5-81)
TRACK 6: BULK VOLUME LAST MONITOR (9-17-81)

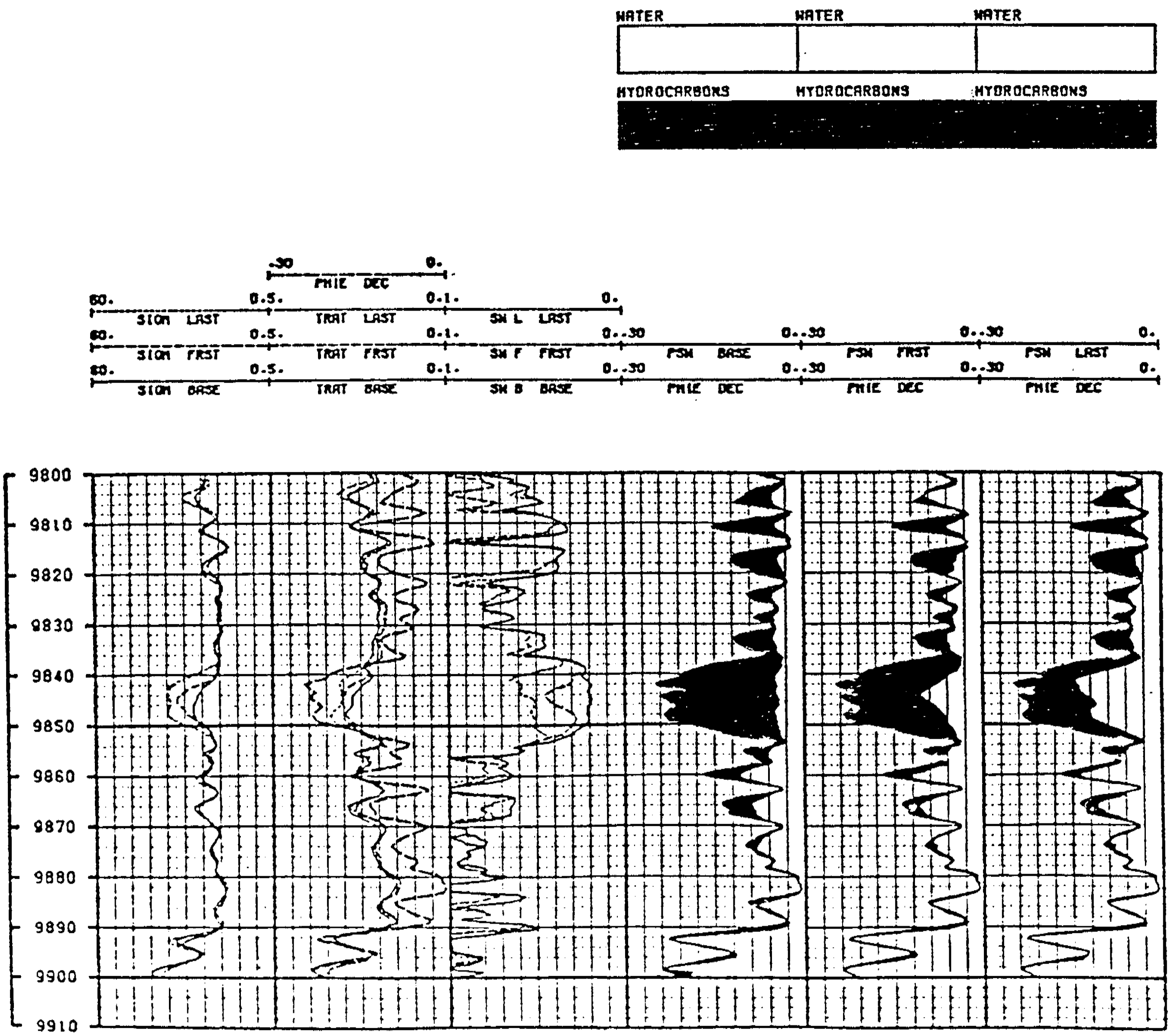


FIGURE 21

LITTLE KNIFE,N.D.
ZABOLOTNY OBSERVATION NO:1
COMPARISON OF GULF AND PETROS FINAL MONITOR WATER SATURATIONS

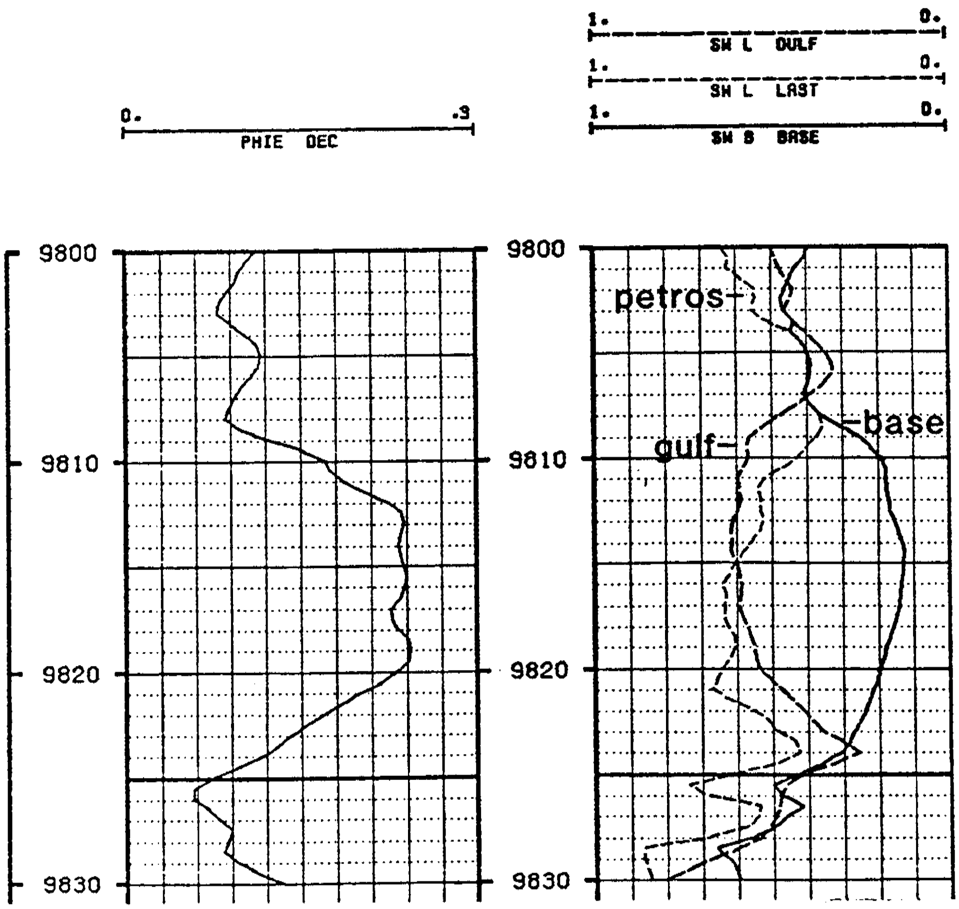


FIGURE 22

LITTLE KNIFE, N.D.
ZABOLOTNY OBSERVATION NO:2
COMPARISON OF GULF AND PETROS FINAL MONITOR WATER SATURATIONS

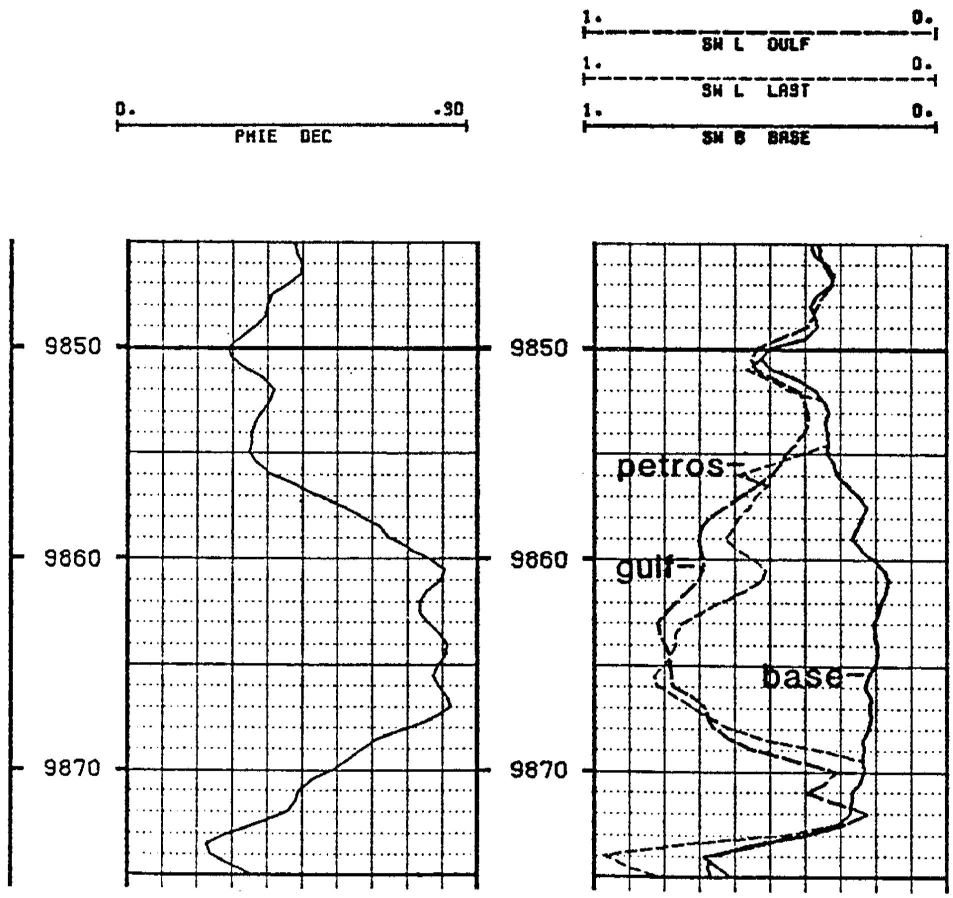


FIGURE 23

LITTLE KNIFE, N.D.
ZABOLOTNY OBSERVATION NO:3
COMPARISON OF GULF AND PETROS FINAL MONITOR WATER SATURATIONS

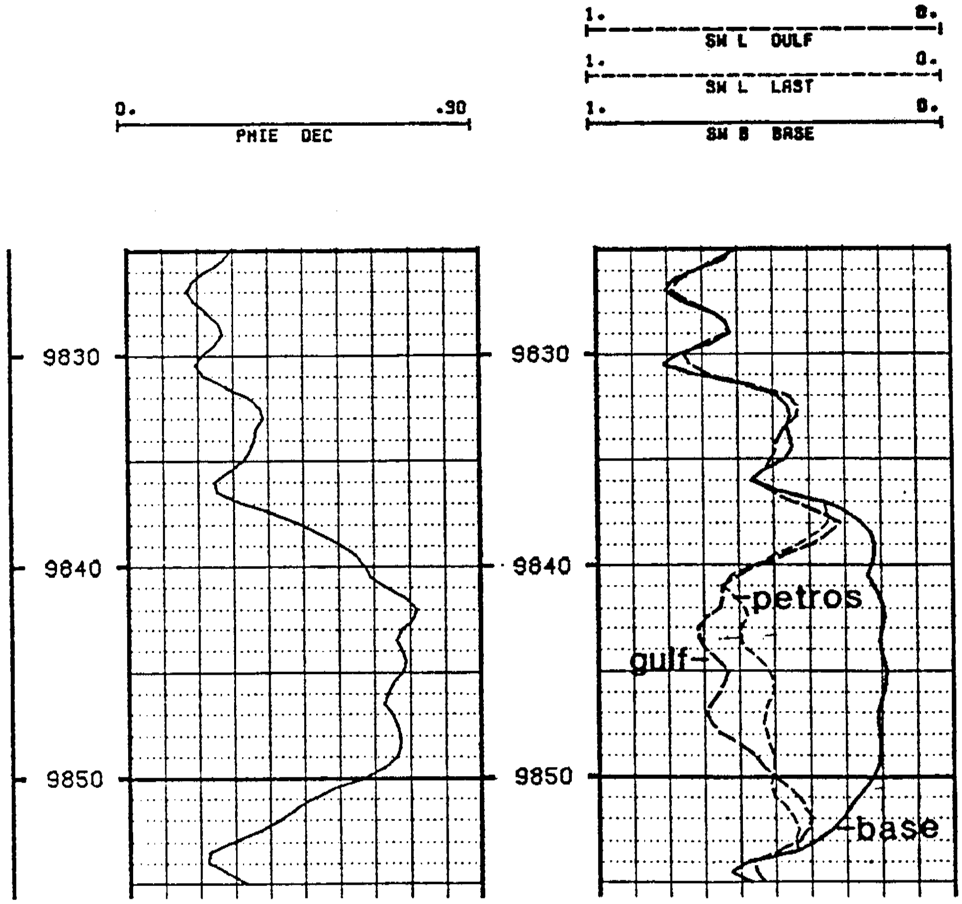
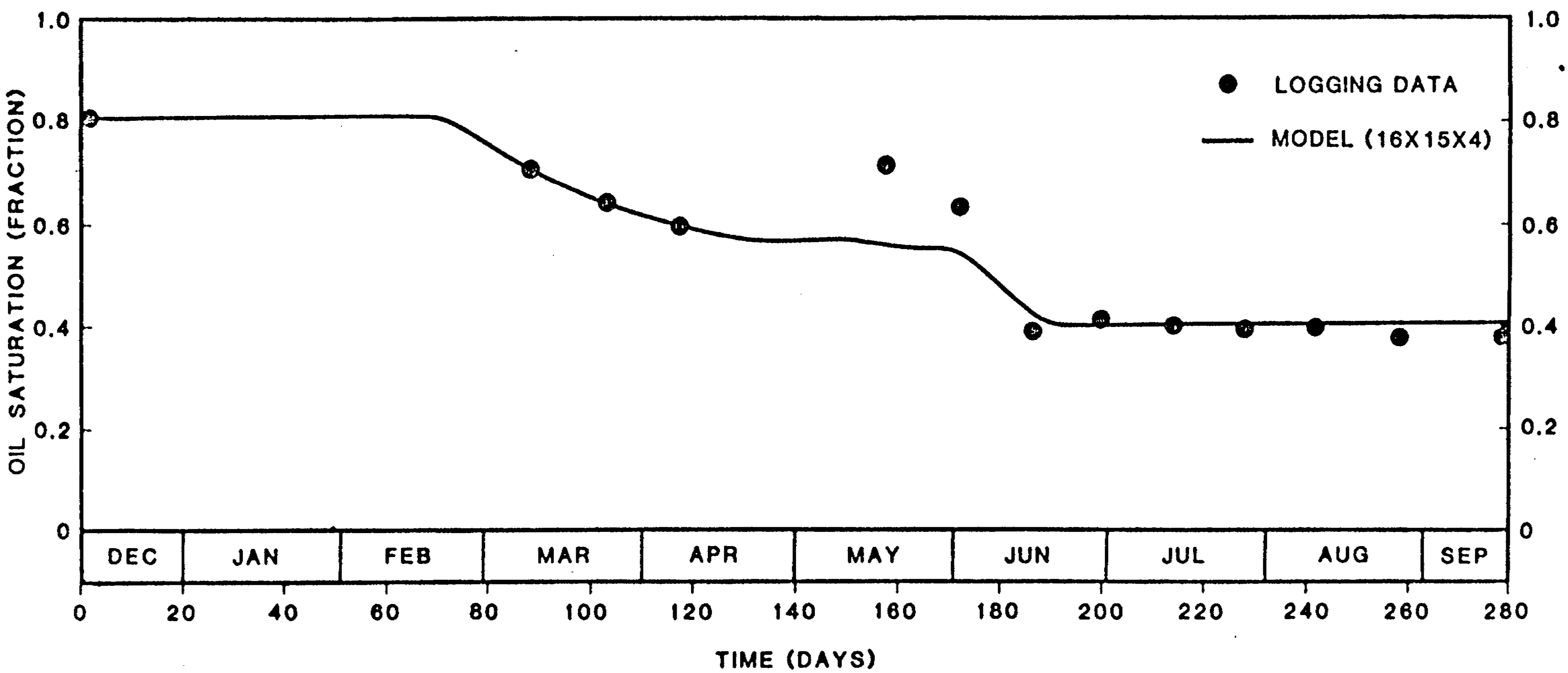


FIGURE 24

OIL SATURATION HISTORY MATCH FOR ZONE D (12-11-80 TO 9-17-81)
ZABOLOTNY OBSERVATION WELL NO. 1

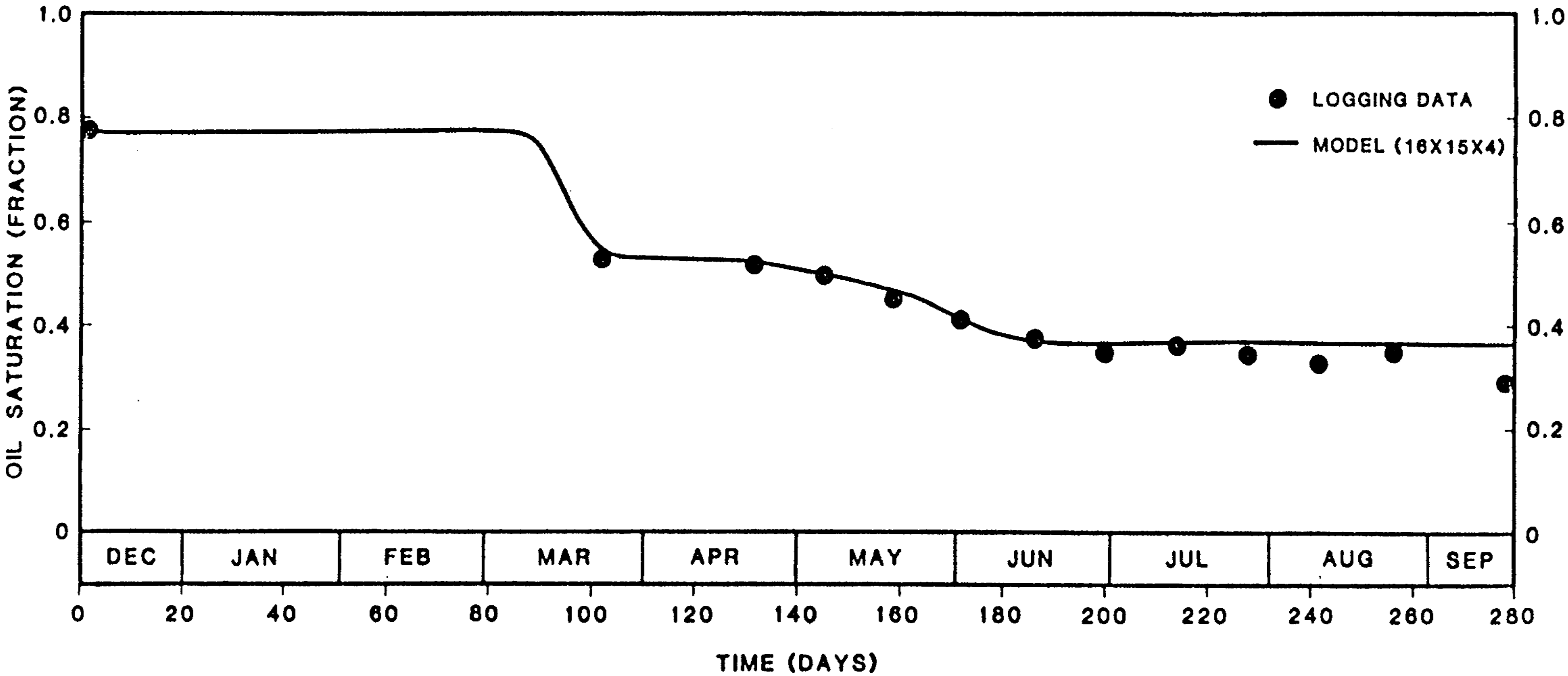


Source: Reference 31, Figure 57

FIGURE 25

OIL SATURATION HISTORY MATCH FOR ZONE D (12-11-80 TO 9-17-81)

ZABOLOTNY OBSERVATION WELL NO. 2

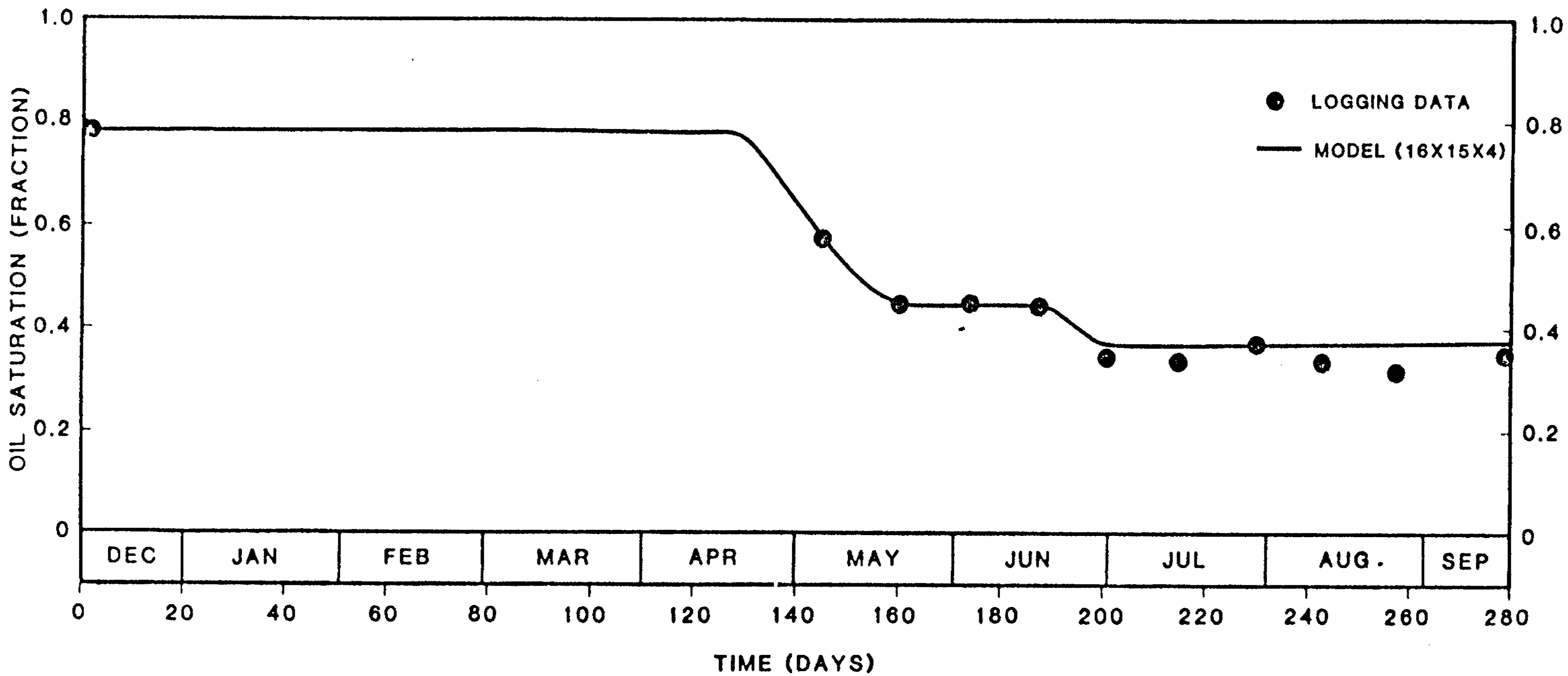


Source: Reference 31, Figure 58

FIGURE 26

OIL SATURATION HISTORY MATCH FOR ZONE D (12-11-80 TO 9-17 -81)

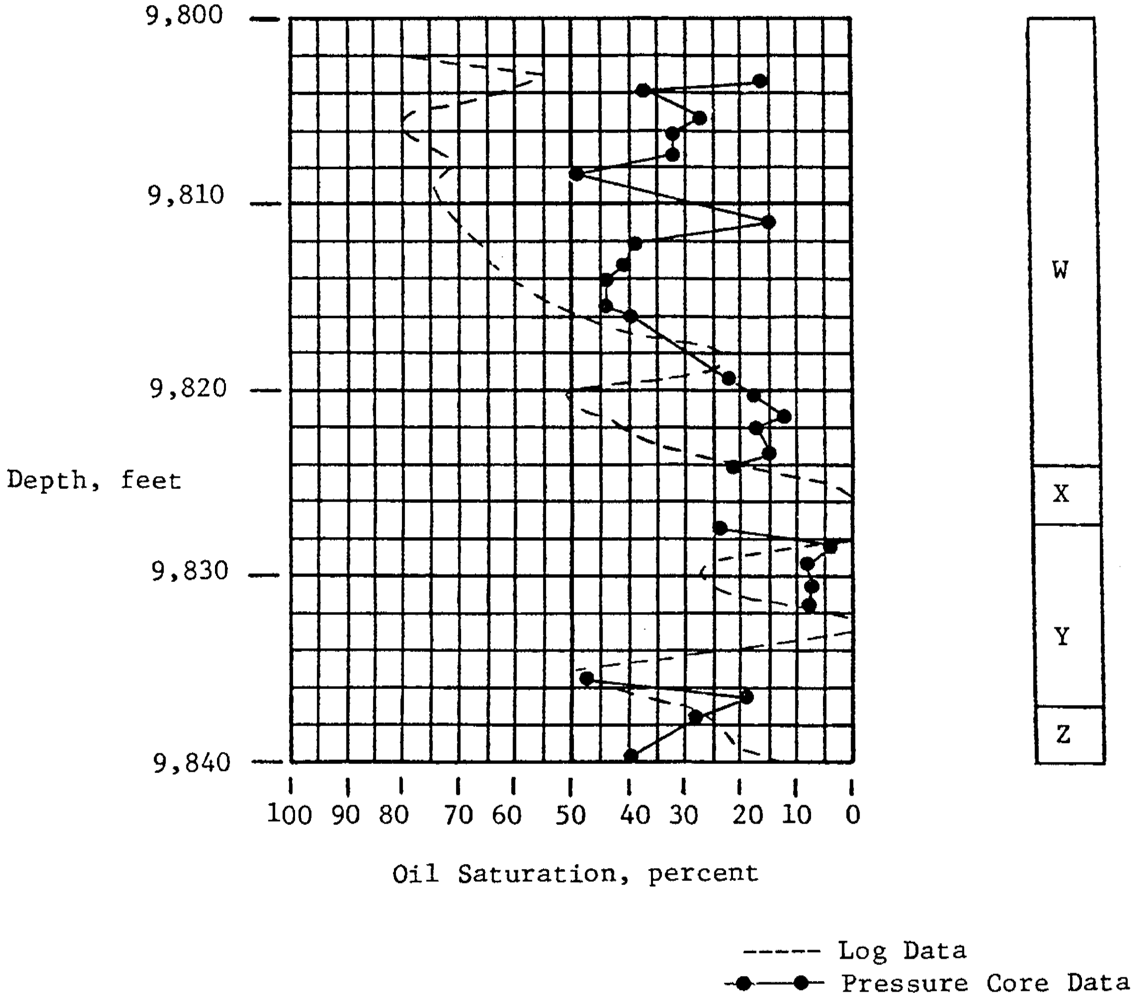
ZABOLOTNY OBSERVATION WELL NO. 3



Source: Reference 31, Figure 59

FIGURE 27

COMPARISON OF LOG-DERIVED AND PRESSURE CORE OIL SATURATIONS



Source: Reference 1, Figure 85 and Table 21

*U.S. GOVERNMENT PRINTING OFFICE: 1986-0-659-031/40015