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A RESERVOIR ENGINEERING STUDY OF A NATURALLY WATER-DRIVEN OIL FIELD

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A thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Master of Engineering (Petroleum Engineer).

Golden, Colorado

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ABSTRACT

This engineering study was done on a small field that is producing from the Red River Formation on the Cedar Creek Anticline, located on the southwest edge of the Williston Basin. The field consists of twelve wells, four of which are still producing. The Red River Formation in this area has a strong natural water drive; the water associated with the water drive is extremely fresh. The freshness of the water causes bio-degradation of the crude oil, which, when combined with the natural water drive, is responsible for the strange production behavior in this field. The purpose of this study was to determine the remaining reserves and the recovery efficiency, and to give recommendations for future production operations.

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INTRODUCTION

This engineering report is a field study of an undersaturated oil reservoir in the Williston Basin on the Cedar Creek Anticline. The purpose of this study was to determine the remaining reserves, predict the future performance, and give recommendations on how best to continue production in the field. At the request of the operator, all of the names and locations of the wells have been changed, and the field name has been changed to "Study Field".

The Cedar Creek Anticlinorium is a major feature on the southwest flank of the Williston Basin, extending for over 100 miles with a northwest-southeast trend. Figure 1 is a regional index map depicting the Williston Basin and an enlarged view of the Cedar Creek Anticline, with a few of the many producing fields shown. Figures 2 and 3 show an aerial view of the general study area and of the Study Field, respectively. All of the wells drilled in the Study Field have been spotted on Figure 3, and a current status map is presented in Figure 4. This map shows the completion zone, initial daily rate, current or final daily rate, cumulative production, completion date, and the current status of each well.

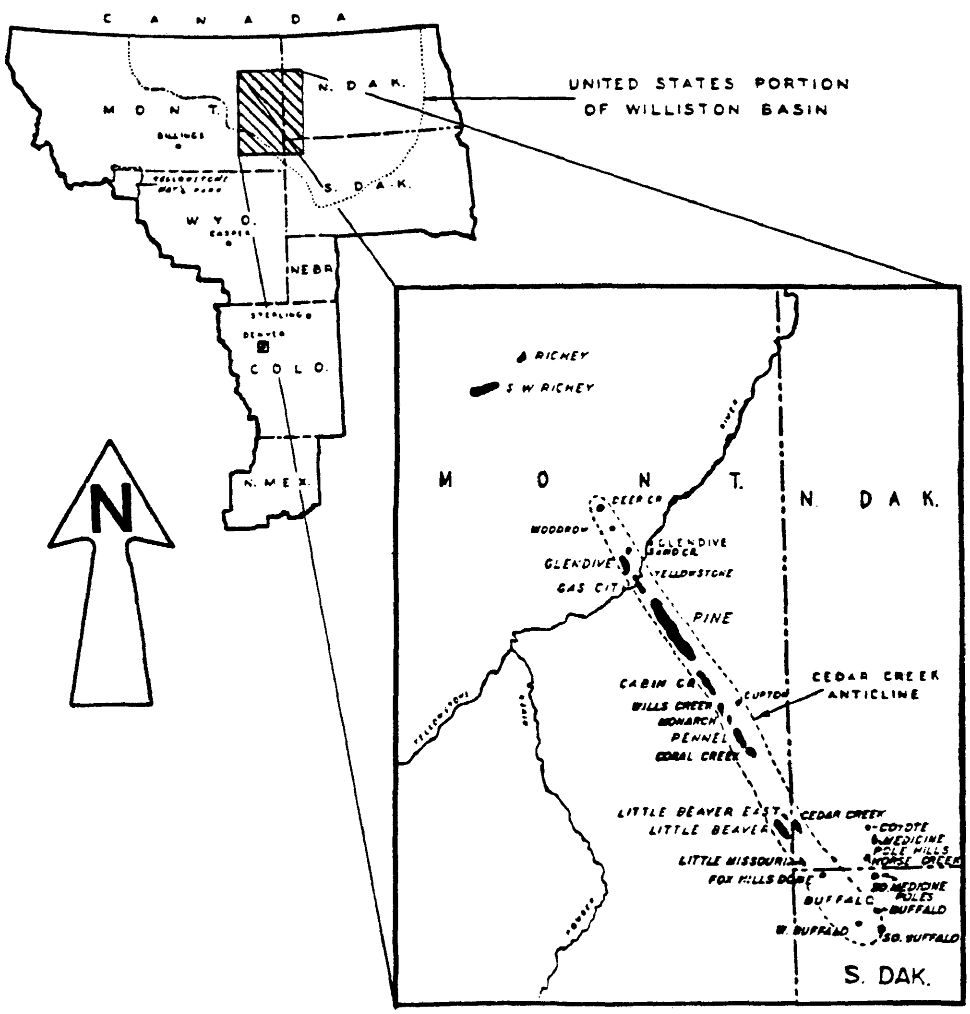
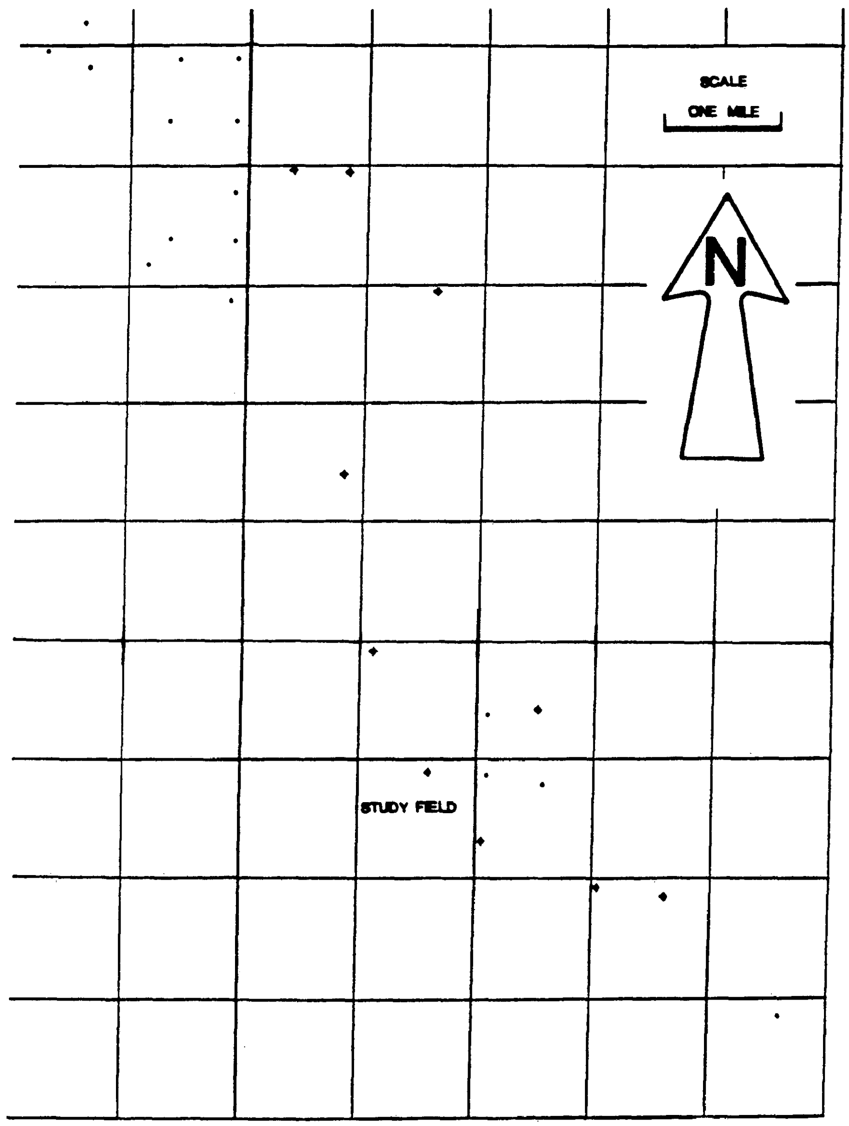


Figure 1. Regional index map.



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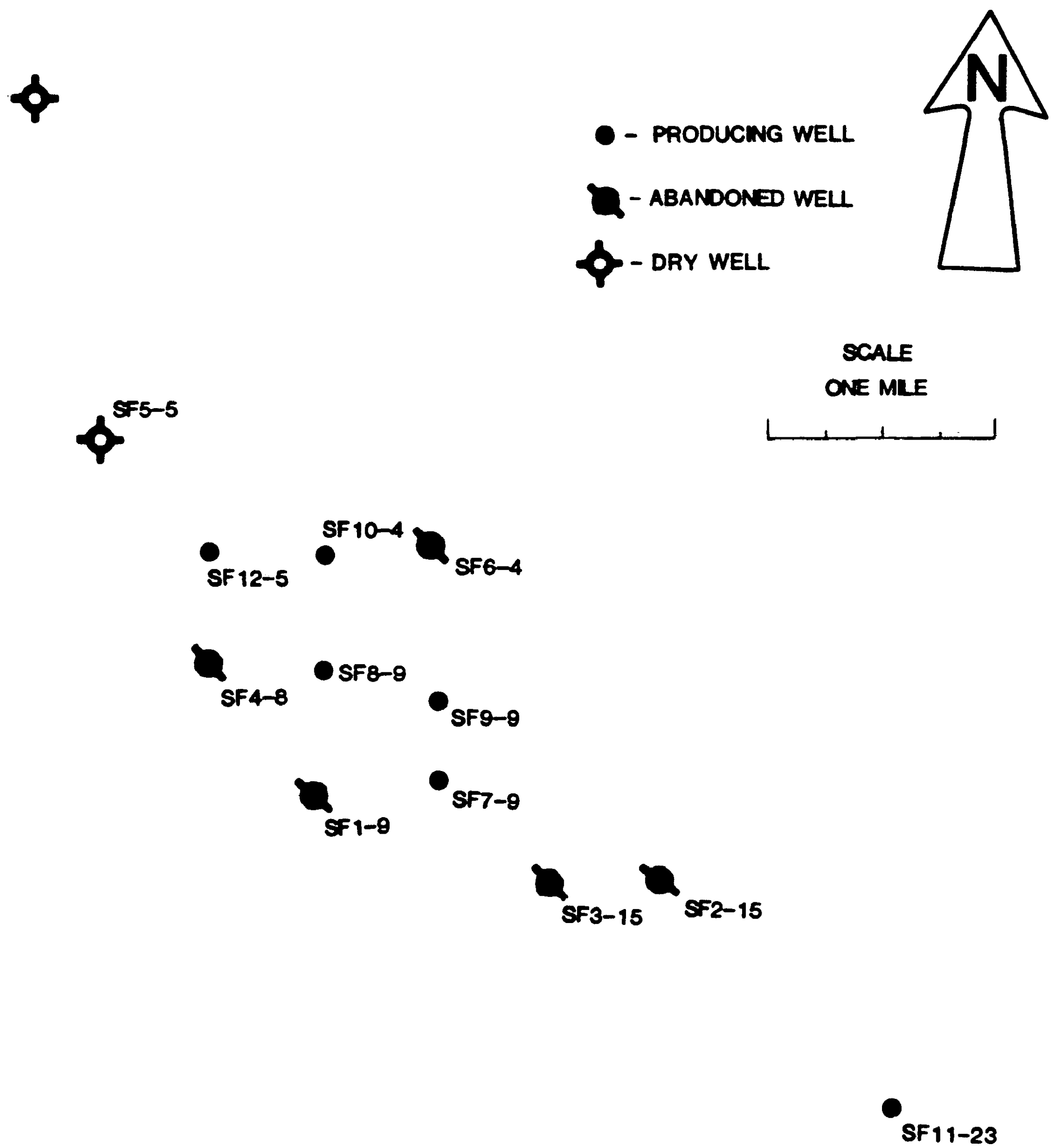

Figure 3. Well spot map.

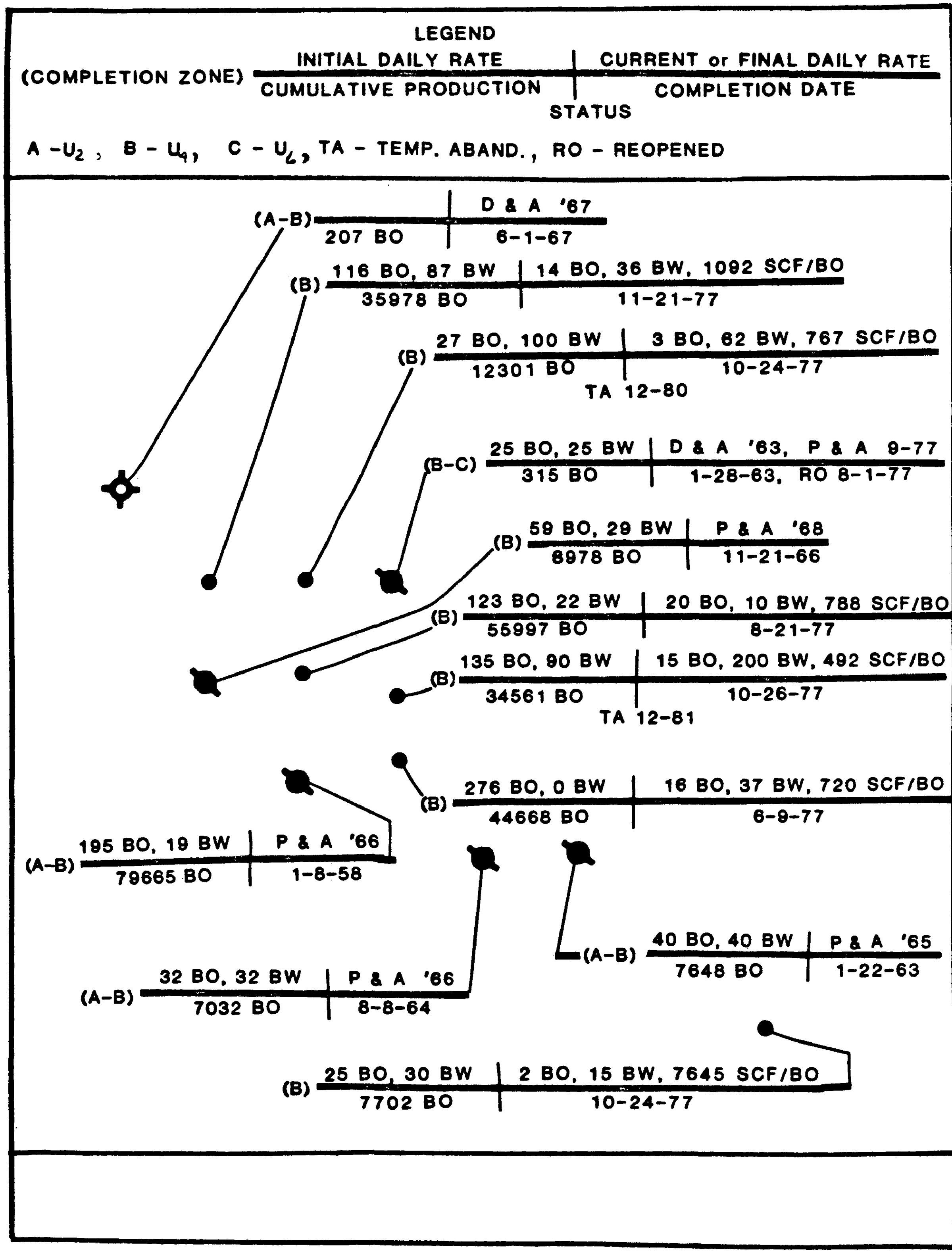

Figure 4. Current status map.

Oil has been discovered in numerous zones of the 3000-foot-thick carbonate section normally penetrated on the Cedar Creek Anticline. Within this carbonate section there may be up to 50 zones of reservoir quality rock with the necessary porosity and thickness to make them of commercial interest (1). To date, the bulk of the production has been from the Ordovician Red River Formation. In the study area, the Mississippian Mission Canyon Formation also has potential as a secondary objective. Production opportunities for each zone have been evaluated. The wells of the Study Field, as most of the fields on the Cedar Creek Anticline, penetrate one of the "bumps" of the Red River node-antinode structure.

The Red River Formation consists of approximately 600 feet of carbonates; 150 feet directly underlying the Stony Mountain Shale are discussed in this paper. The porous producing intervals, which can range from 5 to 70 feet in thickness, are separated by tight dolomites and anhydrites. The Red River carbonates appear to have been flushed with fresh water, and as a result, the trapped crude has been thickened by biodegradation. This gives rise to interesting production problems.

The Study Field has several properties in common with other fields on the anticline, particularly with the nearby Cedar Creek Field. These properties are initial reservoir pressure, crude oil gravity, and initial solution gas-oil ratios. In the Study Field there has been no crude oil analysis for fluid properties; as a consequence, the crude oil properties from the Cedar Creek Field were used in this study.

The study methodology was carried out in a systematic fashion. The first portion of the study involved the acquisition of general well and field data. The well data, in the form of well logs, core analyses, and seismic information, were analyzed. The second phase of the study required the production of an iso-volume map, and the original oil-in-place (OOIP) was determined.

In the third portion of the study, the initial pressures were calculated from the drill-stem tests (DST) and were utilized in the material balance calculations. With the material balance relationship, an OOIP was calculated both with and without a natural water drive. The reason for this was to compare the OOIP under both conditions and ascertain which was more realistic. The results from each calculation were compared with the volumetric OOIP to obtain the most likely value.

Analysis of the production decline curves played a key role in studying the past production history, as well as predicting the future production. This constituted the fourth segment of the study. From the decline curves, an estimation of future performance was derived. In the following section, the major results and recommendations of this study are summarized.

SUMMARY AND CONCLUSIONS

In summary, the reservoir analysis provided the following results.

Geological Background

1) On a regional basis the Red River is capable of producing from four zones, in particular the U_2, U_4, U_6, and U_8. Within the Study Field, the only producing interval is the U_4; all of the other zones are wet, as indicated by either the log analysis, drill-stem testing, or from actual production testing.

2) The rock type is primarily dolomites, with four types of porosity. The primary type is a combination of vugular and moldic porosity.

Petrophysics

1) The water resistivity (R_w) calculated in the Study Field from chemical analyses on the produced

water is 0.10 ohm-m at a bottom-hole temperature of 176°F. This value is slightly lower than the R_w estimated from the Schlumberger R_w catalogs, which was 0.135 at 176°F from the SF1-9.

2) Water chemical analysis patterns indicate fresh water flushing initially and saltier water invading the well at water breakthrough.

3) Water saturation calculations were carried out by both the log-log plotting of deep resistivity versus porosity and utilizing the apparent water resistivity approach as a checking method. The results from both methods were similar in the estimation of water saturation.

Volumetric Original Oil-in-Place

1) The best estimate of original oil-in-place for the U_4 is from the hydrocarbon pore volume map in Figure 13, which resulted in 4,280,000 STBO in place.

Pressure Analysis

1) The initial reservoir pressure in the U_4 zone, estimated from the SF1-9, SF2-15, and the SF3-15,

was 3,820 psig.

2) Upon drilling the SF8-9 in 1977, after a nine-year shut-in, the extrapolated reservoir pressure in the U_4 zone was again estimated to be 3,820 psig.

3) The effective oil permeability was estimated to be 2.0 md from pressure build-up analysis. The effective oil permeability was also calculated through Darcy's radial flow equation, which lent credence to the 2.0 md value calculated from the pressure build-up.

4) The oil-to-water viscosity ratio was calculated to be 8.6, which provides the water with significantly more mobility than the oil. The oil viscosity was estimated from Vasquez and Beggs' correlation, and the water viscosity was estimated from correlations found in Craig's water flooding monograph.

5) Material balance calculations were utilized only to estimate an original oil-in-place range, as there was no pressure history to attempt production history matching. The range that was cal-

culated was 4,288,000 to 6,000,000 STBO originally in-place.

6) The current reservoir pressure is approximately 3,450 psig, as indicated by the fluid level surveys taken in July 1982.

Production Decline Curve Analysis

1) The current average producing gas-oil ratio is 750 SCF/STBO, which, when plotted on a log-linear plot against time, is increasing very slightly.

2) The SF11-23 producing gas-oil ratio is increasing rapidly with time and is of a completely different nature from wells located in the main portion of the reservoir. The current producing gas-oil ratio for this well is 7,645 SCF/STBO.

3) All of the wells, with the exception of the SF1-9 and SF8-9, had initial water cuts greater than 60 percent. The water cuts remain constant until the well begins producing excessive quantities of water. Then the water cut jumps to nearly 100 percent and the oil cut drops off to approximately zero. An example of this is the SF9-9.

These results were compiled and analyzed for the U_4 zone, and the following conclusions were made:

1) The Study Field is under a substantial natural water drive, with an aquifer that is infinite acting. This is indicated by the reservoir pressure. When the reservoir was discovered, the initial pressure was 3,820±75 psig, and after nine years of production and nine years of shut-in, the reservoir pressure was again 3,820±75 psig.

2) There are two drive mechanisms operating separately in the field. The natural water drive is acting over the main structure, while there is a well with a separate drive system isolated in a separate structure, to the southeast, along the strike of the anticline. The isolated well has a combination drive system that consists of a very weak partial water drive and a solution gas drive. This combination system provides a large volume of gas, some water, and very little oil. Thus, this is not a textbook example of a solution gas drive.

3) The strength of the water drive, combined with the high viscosity ratio, causes instantaneous production of uneconomic quantities of water. This is exemplified by the way the production decline curves, namely the water- and the oil-cut plots, change when uneconomic quantities of water are produced.

4) The predicted ultimate recovery has a minimum value of 309,000 STBO and a maximum value of 397,000 STBO, which results in a recovery efficiency ranging from 7.2 percent to 9.3 percent. The remaining reserves are 14,000 STBO to 103,000 STBO, which results in 0.33 percent to 2.40 percent recoverable remaining reserves. This demonstrates the extremely poor recovery efficiency of the Study Field.

5) The poor recovery efficiencies have been attributed to the following factors:

    a) The high mobility contrast between the oil and the water.

    b) The high initial water cut implies that the reservoir has been flushed. This would be similar to the late stages of a water flood where the water front has already broken through.

6) Enhanced oil recovery (EOR) is not a profitable proposition in the Study Field. This is due to:

   a) Small amounts of oil that could be recovered;

   b) The high cost of drilling new wells in the Red River;

   c) The unavailability of some secondary and tertiary recovery constituents;

   d) The high viscosity ratio between the crude oil and the water.

To be more specific, each type of secondary and tertiary recovery process will be considered.

Water Flooding: The only reason for considering this method, in the face of a full natural water drive with complete pressure maintenance, would be to improve aerial sweep efficiency. This would be by making the injection wells appear as pressure sources rather than pressure sinks, which would force the water drive to move between the injectors toward the producers, thus increasing the sweep efficiency. This appears plausible until the increase in recoverable reserves is considered.

Currently, the Study Field will have an extremely low ultimate recovery efficiency, approximately seven to nine percent. The estimated ultimate recovery is between 309,000 and 396,000 STBO. Even if the primary recovery were doubled, it would barely cover the installation costs of three injectors and would, as a consequence, not yield any profit on the investment. Any fewer than three injectors would nullify the sweep efficiency enhancement that is being sought. Therefore, this method is undesirable and will not be considered.

Caustic: The caustic would merely be an addition to a water flood, since the same injection wells would be required. Besides the economic problems, there is enough water present to render the caustic useless in the presence of the water drive.

Carbon Dioxide: The same problems exist for carbon dioxide as for caustic, with the addition of the availability problem in the Williston Basin. Technically, the CO_2 would readily be absorbed into the water and would not affect the oil.

Thermal Recovery: Obviously, the Study Field is too deep and does not have enough permeability to utilize this technique.

Surfactant-Polymer and Polymer: These are still entangled with the economic justification involved with the water flood injectors, as well as being extremely expensive to apply. Polymer treatments to the well bore would last a short time, then the water would shift channels and the problem would recur. Additionally, the injection pressure, combined with the extremely tight nature of this reservoir, would cause technical problems in the application of polymer.

7) The Mission Canyon Formation, as indicated by DST#1 in the SF8-9, would produce mostly water. Therefore, this is not to be considered an economic up-hole potential consideration.

RECOMMENDATIONS

The Study Field will recover only a small portion of the OOIP, however, currently the economics are such that it would be too expensive to attempt to recover additional oil by secondary or tertiary means. Therefore, the recommendation is to produce each well until it begins to produce uneconomical quantities of water, and to follow this by plugging and abandoning according to state and local laws.

This will save both money from being expended in further engineering and company resources from being wasted in attempting to recover additional uneconomic reserves.

GEOLOGY

The Cedar Creek Anticline (Figure 1) is an asymmetrical structural feature which has its origins in early Paleozoic basement faulting (2). Three different episodes of uplift are believed to have affected the area. The first stage of uplift occurred approximately 350 million years ago during the Devonian Period. The second phase of uplift took place between the Mississippian (345 million years ago) and the Triassic Period (225 million years ago), with the third stage occurring after the Paleocene Period (54 million years ago).

The anticline has a northwest-southeast linear fault trend associated with the structure. Figure 5 is a structural contour map of the top of the Red River Formation. In the southwest corner area, a portion of the fault system is illustrated. The fault location was mapped from available seismic data. The anticlinorium, as a whole, exhibits an oscillating node-antinode structure, as seen in Figure 5. The Study Field is on a small symmetrical node within the primary feature; the entire anticlinorium tends to show an asymmetrical shape in cross section perpendicular to the strike, with the steeper side on the southwest flank.

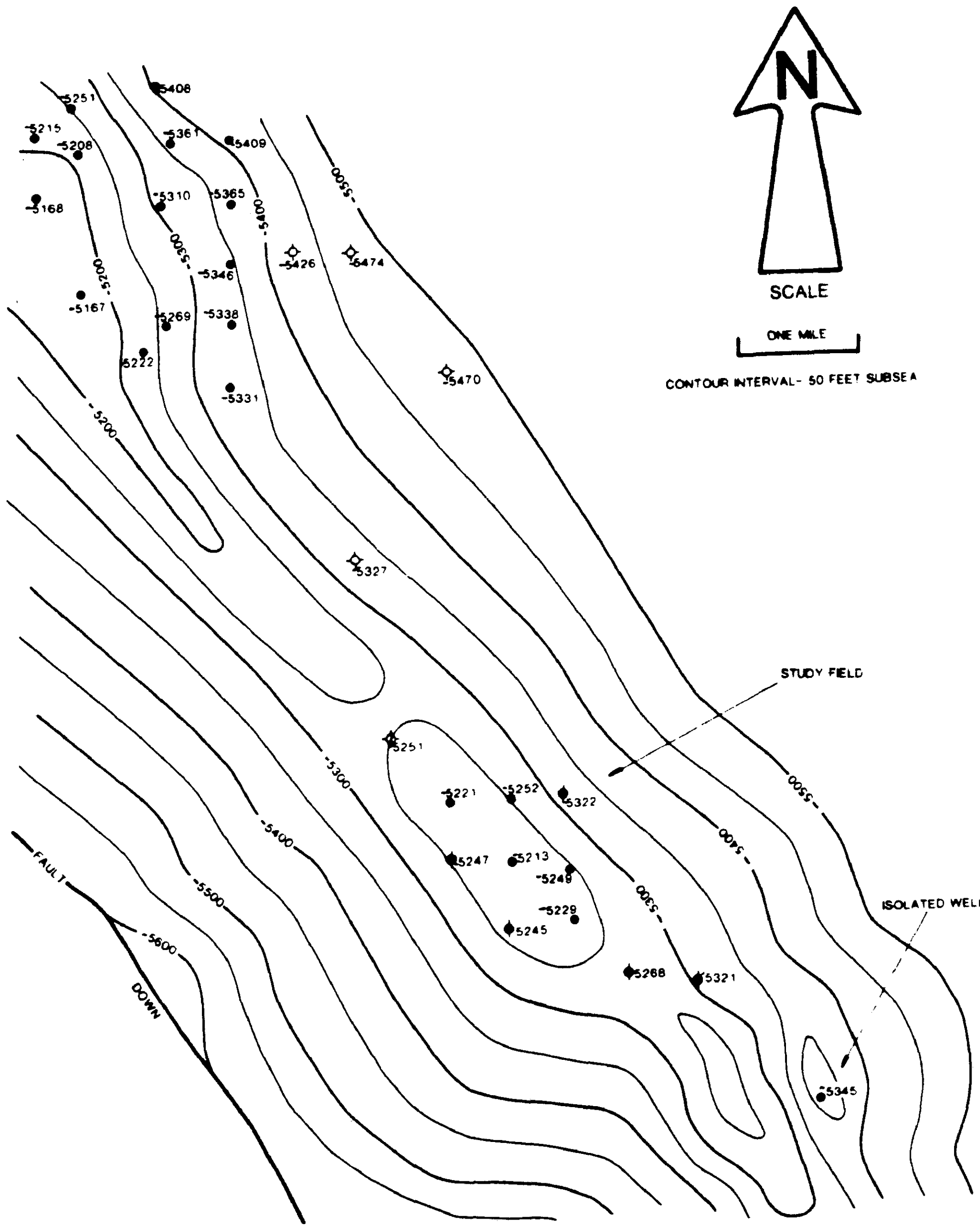

Figure 5. Red River U_4 structure map.

Oil production from the Cedar Creek Anticline is from the 3,000-foot-thick carbonate section, which can contain up to 50 zones with sufficient porosity and thickness to be commercial (1). To date, the bulk of the production has come from the Red River Formation.

The Ordovician Red River (475 million years old) consists of alternating limestone and dolostone sequences. The various geological labels usually associated with the producing and non-producing horizons, as well as the lithofacies breakdown for each horizon, are summarized in Table 1. A more complete petrographic description of deposition, stratigraphic occurrence, and paleontological features is summarized in Table 2.

The depositional environments of the carbonate beds in the Red River Formation consist of a series of three sequences. Each sequence contains sediments deposited in subtidal, intertidal, and supratidal environments that existed on a broad shallow-marine carbonate bank under arid conditions. Figure 6 is a type log illustrating the depositional sequence and the measured neutron-density porosity of the formation. Table 3 is a summary of the relative occurrence of sedimentary structures and grain types of the supratidal, intertidal, and subtidal zones (3).

Table 1. Zone-unit correlation.

UNIT	ZONE	LITHO FACIES**
U_1	Non-Productive	LF(1)
U_2	A	LF(2), LF(3), LF(5), LF(6)
U_3	Non-Productive	LF(1), LF(3)
U_4	B	LF(1), LF(3), LF(5)
U_5	Non-Productive	LF((1)
U_6	C*	LF(1), LF(4), LF(5), LF(6)
U_7	Non-Productive	LF(5)

* Laminated and Burrowed.

** See table 2 for description.

Table 2. Description of upper Red River lithofacies (after Friedman, et al.[3]).

LITHOLOGY	TEXTURE AND GRAINS	FOSSILS	SEDIMENTARY STRUCTURES	ENVIRONMENTAL SETTING	STRATIGRAPHIC OCCURRENCE
Lithofacies 1 Mottled dolomitic biomicrite, wackstone to packstone.	Mainly skeletal grains in peletal-mud matrix; peloids, interclasts & ooids occur.	Echinoderm, brachiopod, byozoa, trilobite, mollusk, ostracod, and gastropod common; rare solitary corals and stromatoporoids.	Massively to poorly bedded, intensely burrowed, abundant horizontal stylolites, local cross & graded bedding.	Subtidal to intertidal zones	Composes U_1, U_3, U_5, limestones; occurs locally in lower part of U_4 and U_6 dolostones.
Lithofacies 2 Mottled dolomitic biomicrite, mudstone.	Skeletal grains in pelletal-mud matrix.	Same as Lithofacies 1.	Massively to poorly bedded, intensely burrowed, horizontal stylolites.	Subtidal zone	Locally distributed in U_2 dolostone.
Lithofacies 3 Finely crystalline dolomite (10 to 60 microns).	Hypidiotopic dolomite.	Traces of small shell debris, mostly ostracod or small brachiopod.	Wavy laminae predominate; flat-pebble breccias, dessication cracks, truncation surfaces, oncolites, nodular anhydrite, & solution breccias are common.	Supratidal zone	Occurs in upper part of U_2 and U_4 dolostones.
Lithofacies 4 Microcrystalline dolomite (< 10 microns).	Xenotopic dolomite.	Same as Lithofacies 3.	Same as Lithofacies 3.	Supratidal zone	Occurs in upper part of U_6 dolostone.
Lithofacies 5 Skeletal dolomite.	Dolomitized biomicrite, wackstone to packstone; locally abundant peloids and interclasts.	Same as Lithofacies 1.	Same as Lithofacies 1.	Subtidal to intertidal zones dolostones.	Occurs in lower part of U_4 and U_6.
Lithofacies 6 Laminated black shale stringers.	Fissile, carbonaceous.	Unfossiliferous.	Locally contain flat-pebble breccia clasts of microcrystalline dolomite; graded bedding.	Supratidal zone marsh deposits	Occurs locally atop U_4 and U_6 dolostones.

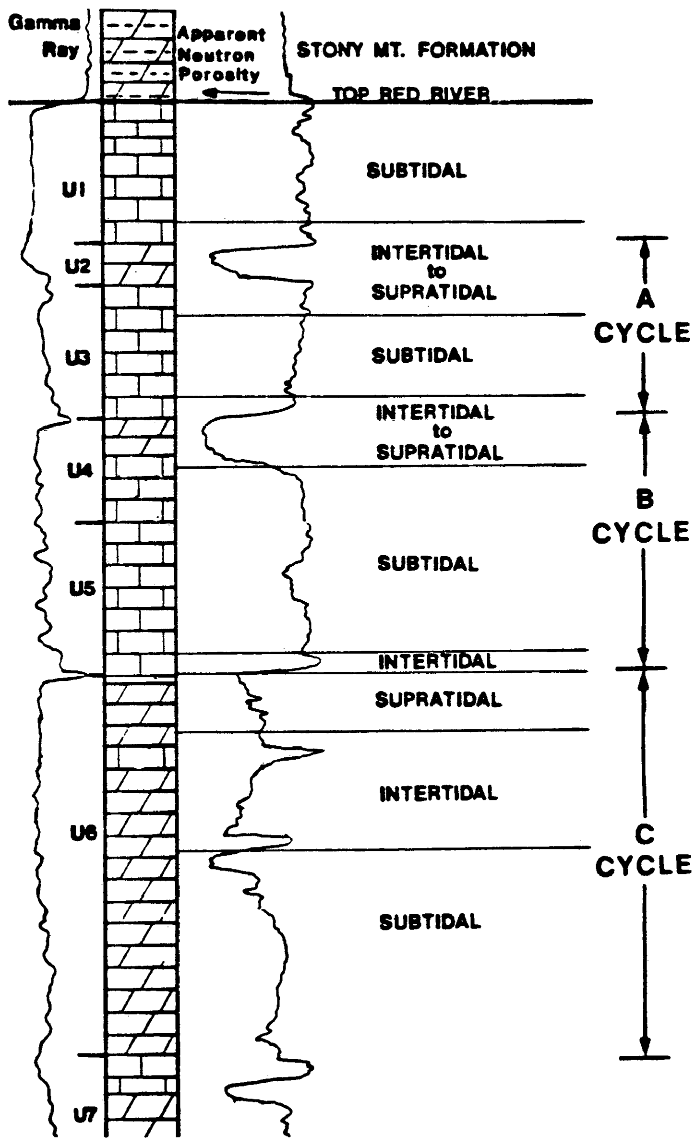

Figure 6. Typical columnar section of the upper Red River formation.

Table 3. Sedimentary structures and grain types of the Red River supratidal, intertidal and subtidal zones (after Friedman, et al.[3]).

STRUCTURES	SUPRA-TIDAL	INTER-TIDAL	SUB-TIDAL
Bedding (>1cm)		C	R
Parallel Laminae (<1cm)	C	C	
Wavy Laminae	D		
Cross Laminae		A	R
Ripple Laminae		C	
Contorted Laminae	C	C	
Graded Laminae	C	C	R
Flat-Pebble Conglomerates	C		
Imbricated Shells		A	C
Shale	C		
Erosional Truncation	C	C	
Chert Nodules	R	C	C
Anhydrite Nodules	C	C	R
Oncolites		C	R
Stylolites	C	C	D
Mottling (Bioturbation)	R	T	D
Solution Brecciation	C		
Lag Conglomerates	C	C	R
Desiccation Features	R-C		
GRAIN TYPES			
Skeletal	R	C-A	A-D
Peloids	A	C	C-A
Intraclasts	R	C-A	R-C
Ooids	T	C	R

D = Dominant, A = Abundant, C = Common, R = Rare , T = Trace

Carbonate sediments accumulate in three major environments associated with tidal flats: 1) subtidal, permanently below low tide in open marine or lagoonal waters, 2) intertidal, between normal high tide and low tide, and 3) supratidal, above normal high tide but within the range of spring or storm tides (4). Generally, the subtidal sediments consist of soft pelletal mud, silt-size carbonates, and skeletal grains. These sediments are usually highly burrowed. Intertidal sediments are similar to subtidal sediments, but with less skeletal debris, less burrowing, and no laminations. Supratidal sediments are highly variable and contain predominantly carbonate muds. Skeletal debris and burrowing are rare, but these sediments exhibit vugs, laminations, and mudcracks. Syngenetic dolomite and evaporites are common constituents.

Porosity is usually secondary in occurrence and is created by dolomitization or leaching. The best porosity is most often developed in the subtidal zone. This can be attributed to two factors:

1) The dolostones of supratidal and intertidal environments are normally microcrystalline, while the subtidal environment creates coarse, sucrosic dolostones.

2) The supratidal and intertidal rocks often show porosity reduction due to secondary anhydrite cement.

As is implied above, the porosity of the Red River is confined to the dolostone units and is a function of diagenesis and depositional environment. In the Red River there are two porosity-controlling diagenetic events: dolomitization and vadose leaching of easily dissolved evaporitic sulfate minerals. There is a minor amount of interparticle porosity which survived diagenesis.

There are four types of porosity within the producing horizons of the Red River. One is primary in nature, and the others are functions of the above-mentioned secondary processes. Primary porosity is interparticle and is usually associated with the high energy environment of the intertidal zone. The principal constituents that make up this rock type are peloids, interclasts, ooids, and skeletal debris with varying amounts of lime-mud matrix.

The other three porosity types have their origins in diagenetic processes. Vuggy porosity is a result of vadose leaching of the easily dissolved sulfate minerals. This takes place in the stage of diagenesis (eogenesis) between final deposition of the sediments and reaching a burial depth, below which significant influence is eliminated by the inability of surface waters to percolate through the sediments (4). The amount of vugular porosity is directly proportionate to the amount of the sulfate minerals present. Therefore, this type of porosity only exists in certain portions of the Red River Formation where the climatic conditions were favorable for sulfate mineral deposition. The general occurrence of this type of porosity is seen in the supratidal environment.

Moldic porosity, the second type of secondary porosity seen in the Red River, results from the leaching of calcite and aragonite after the matrix has been dolomitized, or from the phreatic zone leaching of gypsum particles prior to dolomitization. The name "moldic" is derived from the fact that the size and shape of the pore is determined by the size and shape of the original particles prior to leaching. The moldic porosity is typically found in sediments deposited in intertidal and subtidal environments.

The third and final type of diagenetic porosity is intercrystalline, existing between the crystals of a sucrosic dolostone. It is believed to be formed by non-replaced calcite being dissolved from a framework of euhedral dolomite crystals. It is commonly found at the subtidal-intertidal contact, which suggests a possible relationship to the original depositional environment. Its origin is in the extensive dolomitization characteristic of the subtidal environment, but it can also occur locally in the supratidal and intertidal zones.

The two major producing units in the Red River Formation are the U_4 and U_6. Both are similar in that they have all portions of the depositional cycle, but the U_6 contains a larger cycle (implies longer depositional time) than the U_4 (see Figure 6). The cycle sequence is inverted from the U_6 to the U_4. This inversion implies that the shore advanced in cycle C-U_6, and then receded in cycle B-U_4. As a consequence, the vertical porosity distribution was affected. Friedman, et al. (3) noted that in the Cabin Creek Field the U_4 had porosity decreasing with depth and the U_6 had porosity increasing with depth. This is a direct result of the reversal of the shoreline motion. In addition, they noted that the U_4 had the greater values of porosity and permeability. This can be attributed to two major factors:

1) The length of the eogenetic cycle was reduced for the U_4, thus reducing the anhydrite plugging of the supratidal and intertidal sediments, which is contrasted in the U_6 by a significant change in porosity and permeability of the supratidal and intertidal sequence.

2) The increased porosity of the subtidal zone in the U_6 was caused by more extensive burrowing, and again, it was reduced due to anhydrite plugging.

Lateral distributions of porosity in the U_4 and U_6 are illustrated in the fence diagram in Figure 7. The U_6 zone in this figure is not completely defined. This can be attributed to the fact that the U_4 zone was the primary objective of the operator, and therefore, the wells were not drilled completely through the U_6 strata. Figure 8 is a porosity contour map within the U_4 in the Study Field. Note that there is a northwest-southeast trend to the porosity distribution. This is roughly parallel to the strike of the anticlinal node. Friedman, et al. (3) noted that variations in dolomitic fabric controlled the porosity in the Cabin Creek Field. In the Study Field, there was not enough area to detect much of this. The only conclusion that could be made was that the porosity, as has been mentioned, follows the strike of the anticline.

The U_4 interval thickness remains constant over the length and width of the Study Field. This is depicted in the cross sections in Figures 9 and 10. The cross section is drawn parallel to the strike in Figure 9 and perpendicular to the strike in Figure 10, through the central portion

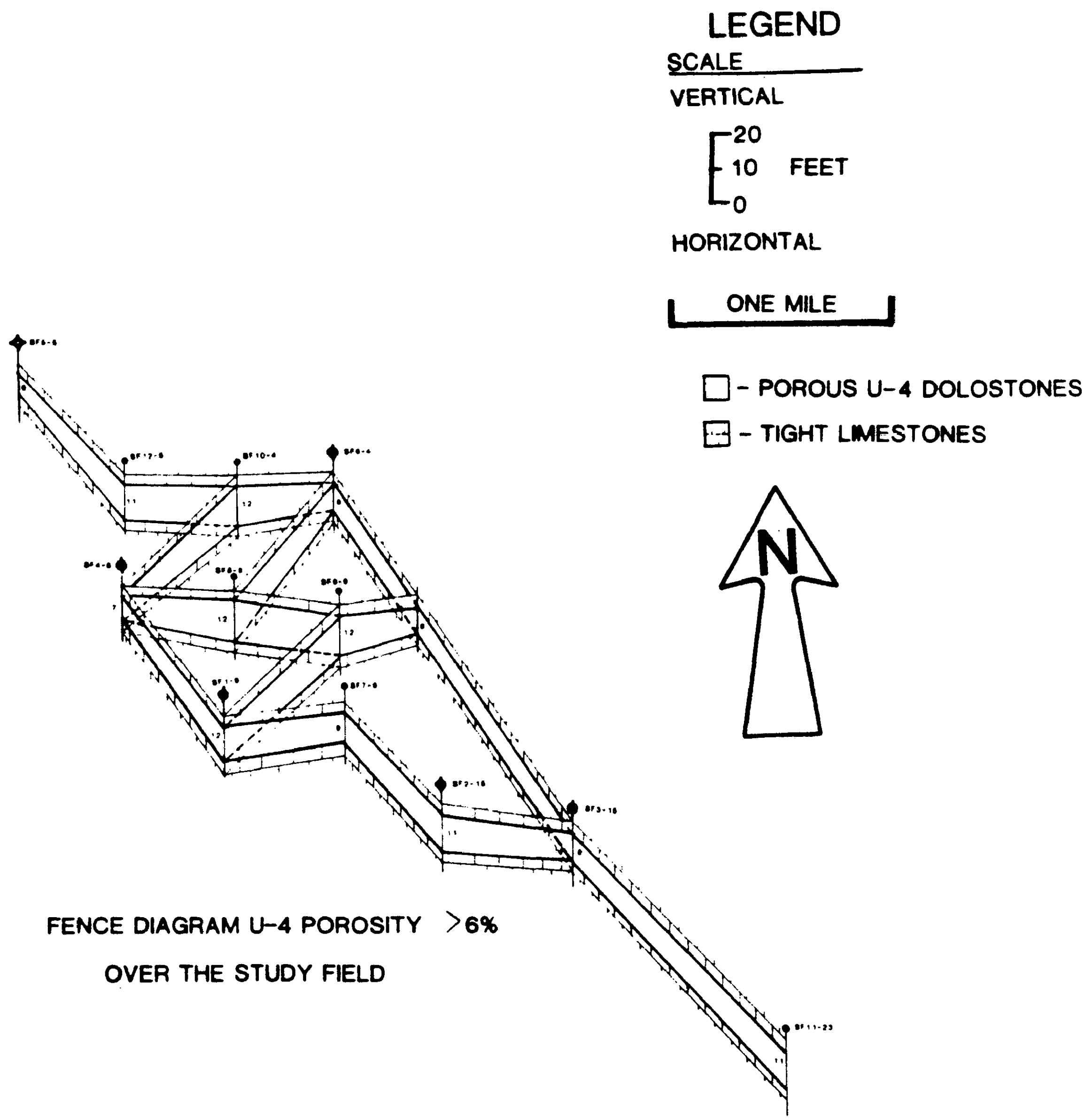

Figure 7. Fence diagram: lateral porosity variations and thickness.

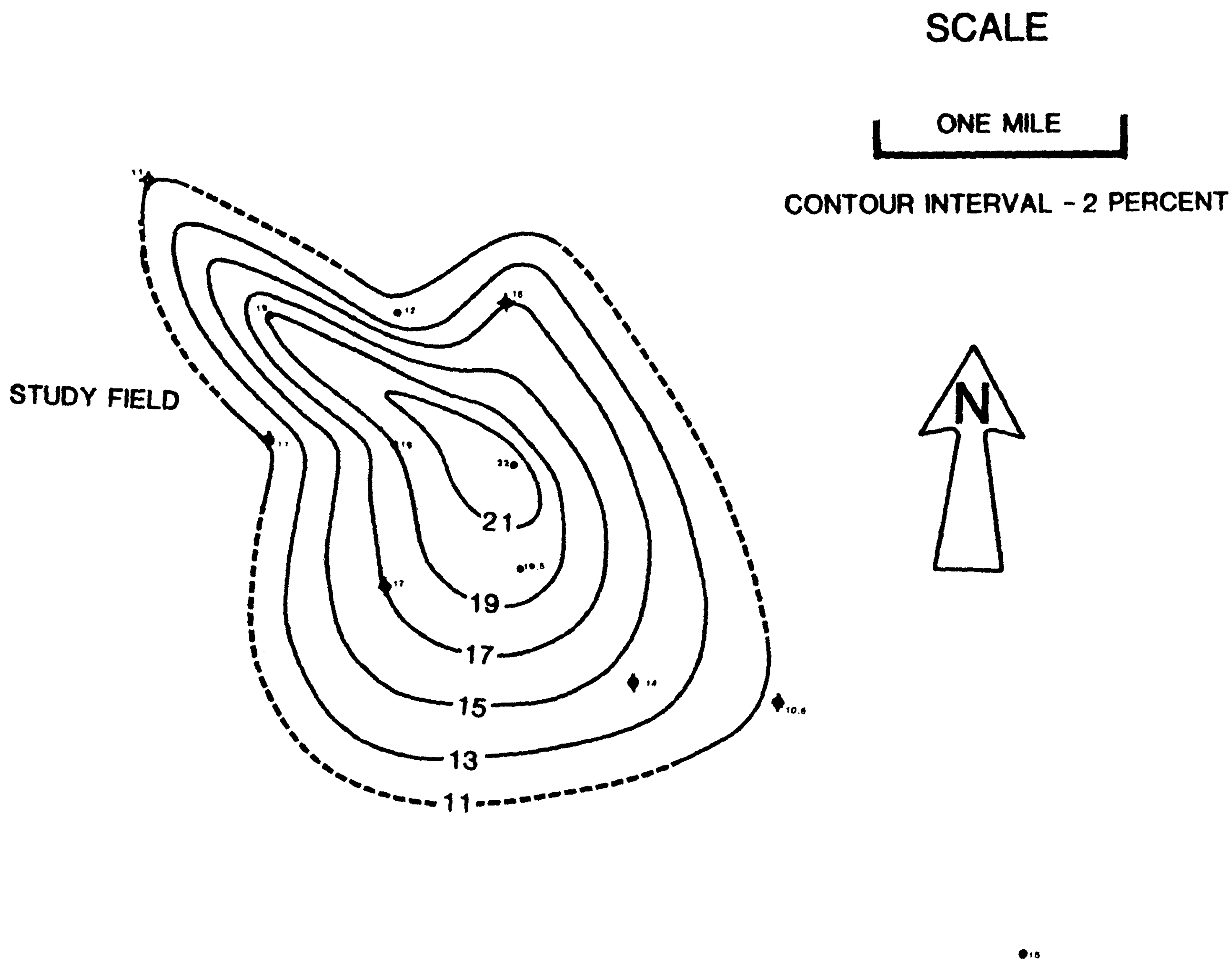

Figure 8. Red River U_4 porosity map.

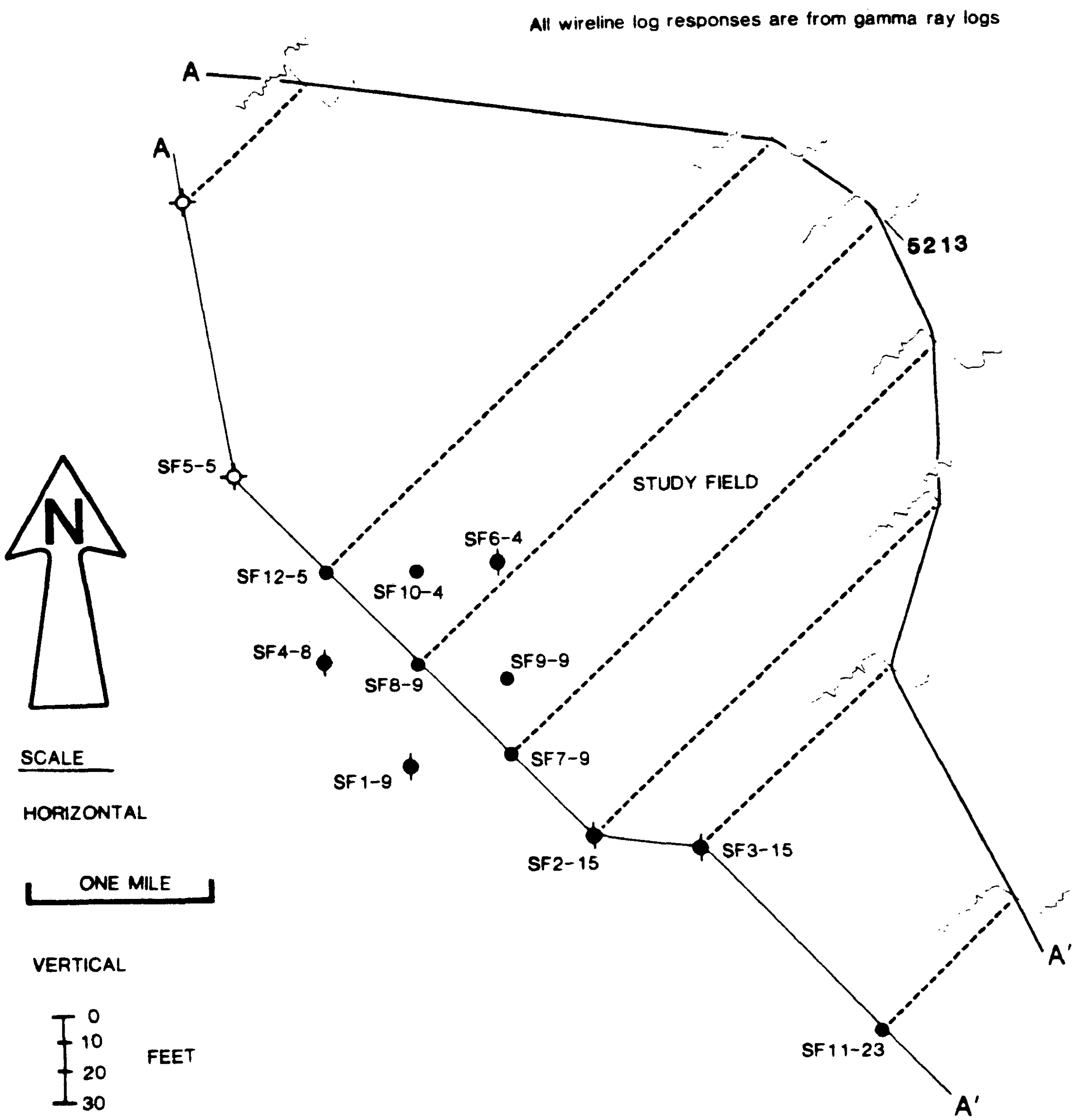

Figure 9. Red River U_4 cross section parallel to the structural strike.

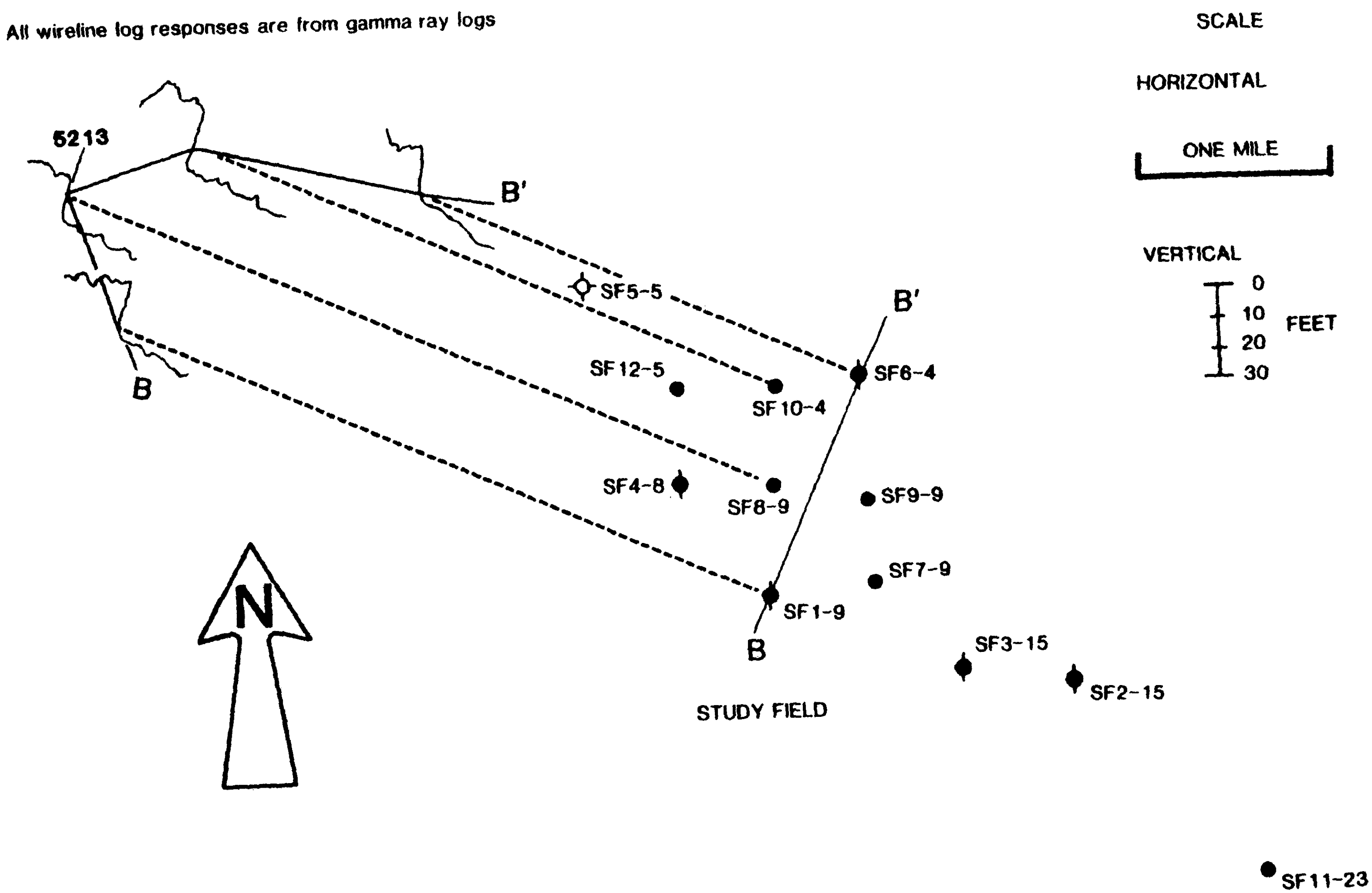

Figure 10. Red River U_4 cross section perpendicular to the structural strike.

of the field. The thickness of the U_4 averages approximately 10 feet throughout the field. For a more complete and articulate discussion on the Red River Formation, the reader is referred to references 3 and 4.

The Mississippian Mission Canyon Formation, as mentioned previously, is a secondary objective in the Study Field. The Mission Canyon Formation sediments were deposited along the Mississippian shoreline in the intertidal zone. Porosity is believed to be primary, although secondary moldic porosity probably exists. The presence of diagenetic permeability barriers and scattered porosity reduction makes productivity of the Mission Canyon difficult to predict in this area.

FIELD AND COMPLETION HISTORY

The Study Field was discovered in November of 1957 with the drilling and completion of well SF1-9. This well was the only commercial producer until 1963, when the SF2-15 was drilled and completed. Over the next three years, four more wells were drilled. These were the SF3-15, SF4-8, SF5-5, and the SF6-4. The SF3-15 and SF4-8 were completed in the Red River U_4 zone, and the other two wells were plugged and abandoned as dry holes. The field produced commercial quantities of oil until mid to late 1968, when excessive water production forced the operators to abandon the remaining producers.

The discovery well was drilled to a total depth (TD) of 6,027 feet sub-sea (SS), or 8,890 feet below the kelly bushing (KB). The top of the Red River was found at 5,247 feet SS (8,100 feet KB), with commercial production in the Red River U_4 at 5,283 feet SS (8,146 feet KB). The initial production rate was 195 stock tank barrels of oil (STBO) per day and 19 stock tank barrels of water (STBW), which is an unusual water cut for the Study Field. Table 4 contains similar data for the rest of the wells in the Study Field.

In May 1977 a second series of drilling was undertaken in the Study Field, which started with the drilling and

Table 4. Well parameters.

WELL	KB (ft)	TD (ft)	TOP OF RED RIVER ft(KB)	PERFORATIONS ft(KB)	INITIAL OIL (STBO PER DAY)	INITIAL WATER (STBW PER DAY)
SF1-9	2,953	8,979	8,200	8,234-8,246	195	19
SF2-15	2,924	8,512	8,245	8,290-8,300	40	40
SF3-15	2,780	8,218	8,138	8,182-8,188	55	65
SF4-8	2,952	8,446	8,201	8,244-8,250	80	30
SF5-5	2,969	8,310	9,220	8,260-8,270	0	0
SF6-4	2,865	8,455	8,194	8,236-8,244	0	0
SF7-9	2,887	8,450	8,116	8,154-8,168	100	150
SF8-9	2,882	8,255	8,095	8,137-8,148	100	20
SF9-9	2,885	8,300	8,132	8,170-8,180	80	90
SF10-4	2,882	8,312	8,134	8,174-8,184	25	25
SF11-23	3,061	8,565	8,410	8,450-8,460	25	30
SF12-5	2,851	8,310	8,072	8,162-8,171	100	80

completion of the SF7-9. Five more wells, SF8-9, SF9-9, SF10-4, SF11-23, and SF12-5, were drilled and completed before January 1978. The SF6-4 was reopened in an attempt to recomplete in the U_4, which failed. The well was re-plugged after producing only 307 STBO. In December 1980 the SF10-4 began producing excessive quantities of water and was temporarily abandoned. The following year the SF9-9 followed suit and was also temporarily abandoned. The SF11-23 has been producing uneconomically for several months due to excessive gas and water production.

In summary, the current field status is that there has been a total of 12 wells drilled. Six of these, all in the first drilling series, are plugged and abandoned. Two of the second series, the SF10-4 and SF11-9, are temporarily abandoned. One, the SF11-23, is producing, but at an un-economical water-cut and gas production rate. The other three, SF7-9, SF8-9, and SF12-9, are still producing economic rates of oil. Table 5 is a summary of the cumulative production of oil, gas, and water for each of the wells and for the field. Also included in Table 5 is a brief summary of completion date, plug and abandonment date, and the net producing life.

The Study Field wells were drilled utilizing the same procedure, with special consideration given to the salt

Table 5. Cumulative production as of July, 1982.

WELLS	CUMULATIVE OIL PROD. (STBO)	CUMULATIVE WATER PROD. (STBW)	CUMULATIVE GAS PROD. (MSCF)	REMARKS COMP.	P&A	LIFE (Yrs,Mo)
SF1-4	79,665	76,398	*	1-58	10-66	8,10
SF2-15	7,648	5,424	*	1-63	10-64	2,10
SF3-15	7,032	17,430	*	8-64	8-66	2,1
SF4-8	8,978	23,751	*	11-6	8-68	1,10
SF5-5	207	1,936	*	6-67	8-67	0,2†
SF6-4	307	*	*	2-63	2-63	0,0††
SF7-9	44,668	84,408	19,932	5-77	**	
SF8-9	55,997	26,589	25,794	8-77	**	
SF9-9	34,511	60,451	18,047	10-77	12-81	4,2
SF10-9	12,301	62,384	10,089	10-77	12-80	3,2
SF11-23	17,702	265,150	13,492	10-77	**	
SF12-5	35,998	45,119	34,126	11-77	**	
Total	294,994	430,039	121,480			
First Series	103,530	124,939				
Second Series	191,464	305,100	121,480			

* Not recorded

** Still producing

† Reopened 11-77

†† Replugged 12-77

stringers in the Charles Formation. Surface casing, usually 8-5/8 inch K-55, was set between 1,000 feet and 1,500 feet KB to isolate the fresh surface waters. A salt-based drilling mud was used below surface casing throughout the rest of the wells. The chloride content of the mud filtrate was kept in excess of 100,000 ppm. Deviation of the well bore was not required, as all surface locations were accessible. Several cores were taken in the drilling operations, however there were no changes in the drilling fluid at the time of coring. DST's were a common practice; they were used to determine a reasonable estimate of the water resistivity and primarily to determine if the zone was productive, as oil-stained cuttings were common and not sufficient to define the producing zones. The log suites run on the Study Field were a combination of resistivity, acoustic, and radioactive logs. Table 6 is a listing of the wells and specific logs that were run and analyzed. The wells were cased with 5-1/2-inch, N-80, 17-pounds-per-foot (PPF) to 20-PPF long string, which was cemented in two stages.

Completion procedures varied among the operators working in the Study Field. SF1-9 and SF2-15 were perforated with bullets, and the others with jet shots. Usually, the operators used two to four shots per foot (SPF).

Table 6. Wireline logs.

WELL	LOGS RUN	LOGS ANALYZED FOR STUDY
SF1-9	ML, ES, GN	ES, GN
SF2-15	ML, LGN, S	LGN, S
SF3-15	ML, LG, S	LG, S
SF4-8	LG, CSL	ALL
SF5-5	ML, LG, CSL	LG, CSL
SF6-4	ML, LGN, S	LGN, CSL
SF7-9	DL, CSL, D-N	ALL
SF8-9	DL, D-N	ALL
SF9-9	DL, D-N	ALL
SF10-9	DL, D-N	ALL
SF11-23	DL, D-N	ALL
SF12-5	DL, D-N	ALL

ML = Micro-Laterolog *

ES = Electric Survey +

LG = Laterolog-Gamma Ray +

LGN = Laterolog-Gamma Ray-Neutron +

DL = Dual Laterolog

S = Sonic +

CSL = Compensated Sonic-Gamma Ray

GN = Gamma Ray-Neutron **

D-N = Compensated Neutron-Formation Density

* Only used as a correlating device

** Analyzed by old log techniques

\+ No correction applied

All of the perforations were acid washed with 500 gallons to 1,500 gallons of 15 to 28 percent hydrochloric acid (HCL). The perforations were then matrix acidized with 5,000 to 10,000 gallons of 15 to 28 percent HCL acid. In some cases, acid fracture was substituted in place of the matrix acidization. In these cases, the same 5,000 to 10,000 gallons of HCL acid was used, but another 10,000 to 15,000 gallons of gelled propant carrying fluid would follow the acid, carrying 2 to 3 PPG of 100 mesh sand. Characteristic fracture pressures were 1,000 to 2,500 psig over the fluid column weight. If these pressures were exceeded, communication behind the pipe occurred.

Once production was established, the wells were placed on rod pumps. The production rate of the formation is such that the wells pump off in eight to ten hours, and as a consequence, time clocks are utilized for intermittent production. The production stream is separated, and the crude oil and water is stored in tanks. Due to the low producing gas-oil ratio (R_p) of the produced crude oil, the gas is either used on location for surface facilities or vented to the atmosphere.

Appendix A contains researched well data, covering drilling and completion information and any associated problems. Also included are well data from Petroleum Information

Corporation for each well in the field, as well as one outside the field boundary.

PETROPHYSICS

The petrophysical analysis of the Red River Formation is notorious for its complex nature in the vicinity of the Cedar Creek Anticline. Due to fresh water flushing of the anticline, highly variable water salinities exist both vertically and laterally. An associated problem is residual oil shows in porous rock that produce only water. The combination of these two factors can be very misleading, and often pipe is set on non-commercial wells by inexperienced personnel.

Wireline logs are forced to take a "back seat" to drill-stem and production testing, as this is the only way that oil production can be verified. With fresh water flushing of the strata occurring in an unpredictable manner, the best way to determine the formation water resistivity, R_w, is by a sample of actual produced fluid from the zone of interest.

Formation Water Resistivity, R_w

In the Study Field, produced water samples have been analyzed from the second series of drilling which started in 1977. Each of the six wells drilled have had a yearly water analysis. The water analyses indicate the concentration of minerals or ions, called solids, present in the water at the time of sampling. Two to three water analyses from each well were examined, and via a method presented by Hilchie (5), the concentration of each of the ions was converted to an equivalent concentration of sodium chloride (NaCl). This was then summed to give the total equivalent concentration of NaCl for the sample, and subsequently converted to an equivalent R_w, which was found to be 0.1 ohm-m. Listed in Table 7 are the concentrations, in parts per million (ppm), of each ion, the total concentration, and an average for all wells. Also, the total equivalent concentration of NaCl and the associated R_w at the formation temperature of 176°F for each well has been included, as well as an average R_w for the initial and present conditions. The initial condition was the first water analysis performed on each well, and the present condition was the most recent analysis.

Water Pattern Analysis

Table 8 is the ion concentration in milliequivalents per liter (MEQ/L). This table provides the data for the pattern comparison of Figure 11. These patterns were developed with Stiff's (6) method. In Figure 11, the initial pattern, June 1977, for the SF7-9 was from a sample taken just after the isolation of the U_4 zone. It is very similar

Table 7. Ion concentration in ppm with equivalent NaCl concentration and R_w.

		ION CONCENTRATION (ppm)						
		WELL SF7-9	WELL SF8-9	WELL SF9-9	WELL SF10-4	WELL SF11-23	WELL SF12-5	AVERAGE
HCO_3	I	488	305	305	354	354	305	303
	P	390	342	488	488	451	366	421
Cl	I	13,475	16,134	15,430	16,154	14,466	16,395	15,224
	P	14,042	15,318	18,297	27,657	12 765	15,318	17,233
SO_4	I	2,259	1,201	2,650	1,050	2,250	1,050	1,604
	P	1,950	1,800	2,700	1,200	1,350	3,300	2,050
Ca	I	782	782	812	771	1,015	974	1,129
	P	730	730	893	649	730	812	757
Mg	I	219	292	345	271	247	296	469
	P	148	124	222	296	99	137	171
Na	I	8,690	9,702	9,314	9,682	8,946	9,567	8,650
	P	9,061	9,843	11,866	17,386	8,049	10,441	11,108
Total	I	25,913	29,146	25,705	28,233	27,278	28,587	31,964
	P	26,321	28,157	34,466	47,676	23,445	30,374	31,739
Equiv. NaCl Concentration	I	23,601	27,510	23,854	26,497	25,487	27,608	
	P	24,793	26,692	32,361	46,390	22,197	28,035	
R_w (ohm-m)	I	0.117	0.105	0.117	0.100	0.109	0.100	0.108
	P	0.116	0.103	0.085	0.064	0.112	0.100	0.097

I = Initial test, March 1978 P = Present test, January 1981

Iron (Fe) was not present in any of the wells except the SF11-23. In this well the concentration of Fe was 430 ppm for the initial test and 0 ppm for the present test.

Table 8. Ion concentration in MEQ/L.

		ION CONCENTRATION (MEQ/L)					
		WELL SF7-9	WELL SF8-9	WELL SF9-9	WELL SF10-9	WELL SF11-23**	WELL SF12-5
HCO_3	I	8.0	5.0	5.0	5.0	5.8	5.0
	P	6.4	5.6	8.0	8.0	7.4	6.0
Cl	I	380.0	455.0	435.1	455.5	407.9	462.3
	P	396.0	432.0	516.0	779.9	360.0	432.0
SO_4	I	47.0	25.0	551.0	21.8	46.8	21.8
	P	40.6	37.4	56.2	25.0	28.1	68.6
Ca	I	39.0	39.0	40.5	38.5	50.6	46.6
	P	36.4	36.4	44.5	32.4	36.4	40.5
Mg	I	18.0	24.0	28.3	22.3	20.3	24.3
	P	12.2	10.2	18.2	24.3	8.1	11.3
Na	I	378.0	426.0	405.1	421.1	389.1	416.1
	P	394.0	428.1	516.1	756.3	350.1	454.2

I = Initial test, January 1978 P = Present test, January 1981

** Fe was only found in this well's analysis. The concentration of Fe was 7.71 MEQ/L for the initial test and 0 MEQ/L for the present test.

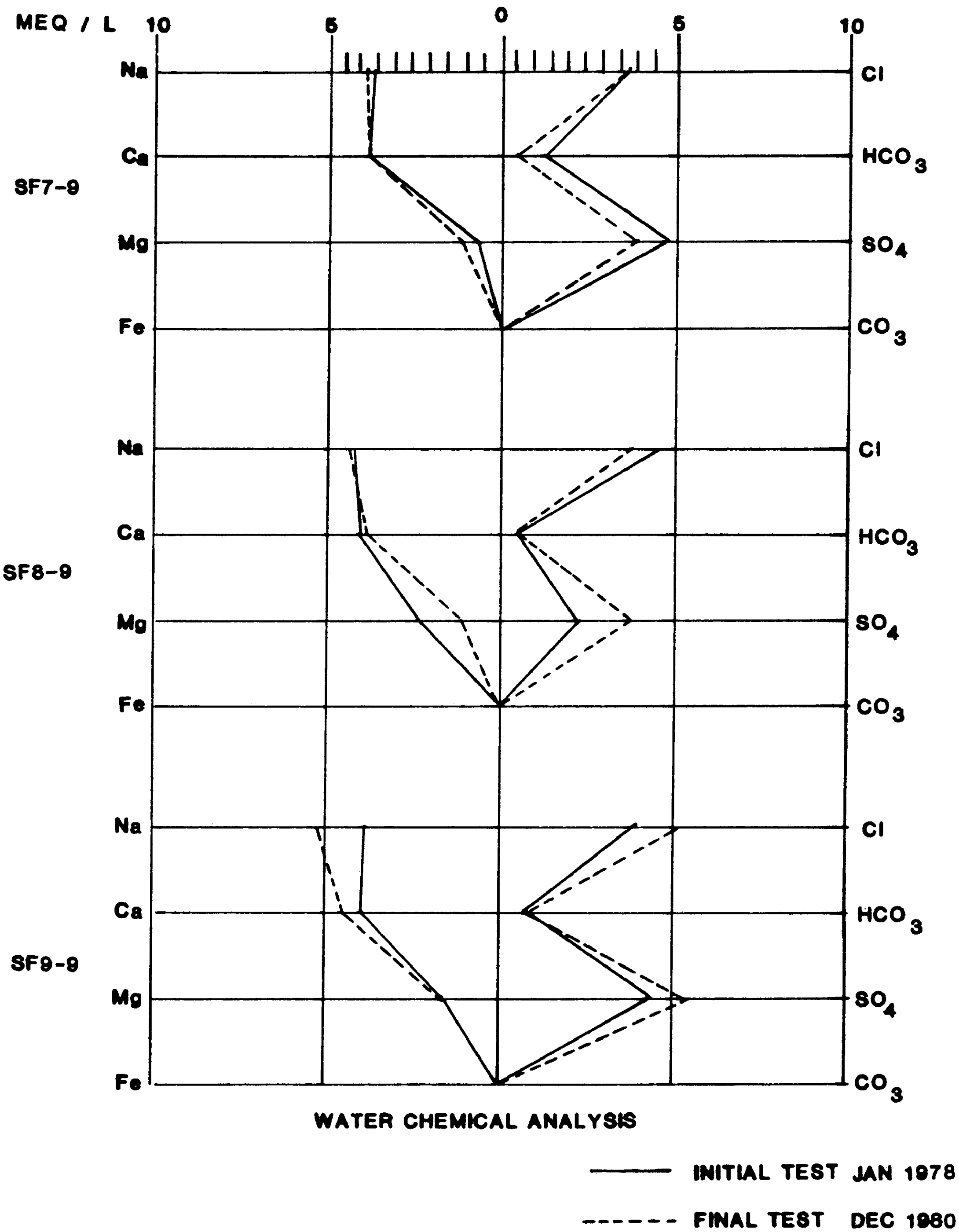

Figure 11. Water chemical analysis: ion concentration patterns.

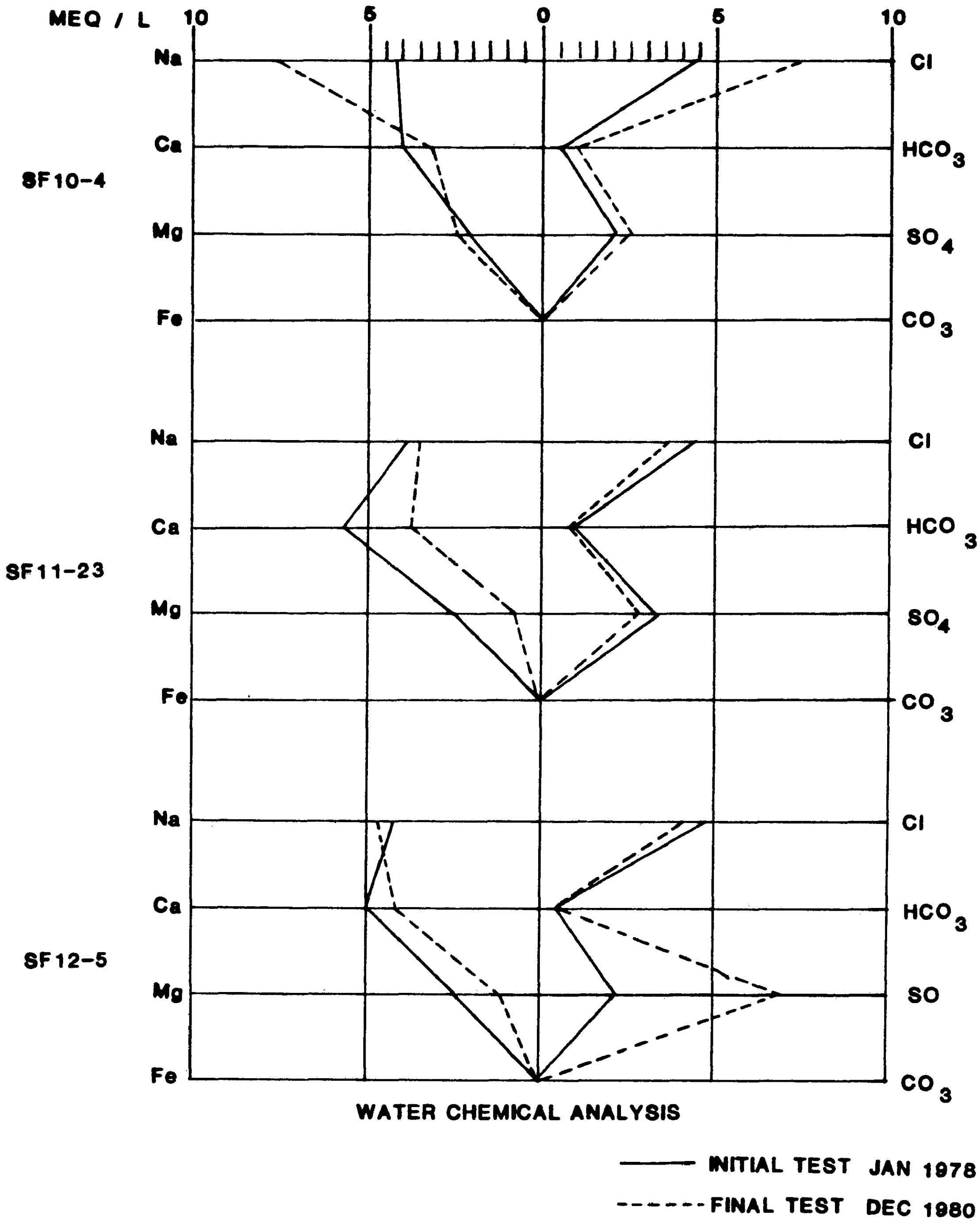

Figure 11. (Continued)

to the patterns from the samples taken from the same well in March 1978 and January 1981. The only change among these three patterns is a decrease in the Na and Cl over time. The intermediate patterns for SF9-9 and SF10-4 are the same as SF7-9, but a change occurs between the intermediate and final patterns of each well; the Na and Cl concentrations increase. The concentrations of these from SF9-9 become very similar to those of the initial test in the SF7-9. The changing ion concentrations of SF10-4 increase beyond the initial values for these ions found in SF7-9.

There are two possible conclusions for this behavior. One is that the aquifer water in the formation is more salty (in the form of Na and Cl), and the other is that as production occurs water is drawn from lower strata into the U_4 zone, which would indicate some type of a fracture system or vertical permeability. Based on the data present, this was a difficult problem to decipher.

Consider the following:

1) The SF7-9 was fractured after perforation in the U_4. The excessive fracture pressure broke the cement isolating the U_4 from the lower zones. The remedial operation was to perforate and squeeze in two

places in the U_6 zone. The water production rate was halved, and the initial water sample was analyzed. The water cut remained too high, so in November 1977 the perforations of the U_4 were squeezed.

The zone was reperforated, and this time acidized with less pressure. In March 1978 the intermediate sample was taken and analyzed at the same time as all of the other wells currently producing. The samples that were taken during this time, as can be seen in Figure 11, nearly overlay each other.

2) In December 1980 a second sample was taken from the SF10-4, as this well had started to produce excessive water. The sample was analyzed, and the results indicated a significant increase in the Na and Cl levels. The remaining wells had a sample taken the following month, in January 1981. All of the samples that were analyzed in January 1981 are plotted as the present curve in Figure 11.

Again, the patterns could be overlayed for all of the wells, with two exceptions: the SF9-9 and SF10-4. Both wells showed changes in the same ions, but the SF9-9 was not as significantly affected. From the production history, the water that was produced by the SF9-9 and SF10-4 was 45,709 STBW and 62,384 STBW, respectively.

3) With respect to the fracture and vertical permeability idea, wells with as much production as the SF9-9 and SF10-4 should also show the effect of lower zone water in the same fashion. This was not the case, as the SF7-9 had produced 96,736 STBW and the SF12-5 produced 35,174 STBW as of January 1981. The associated pattern, from the SF7-9 and SF12-5, was the same as the intermediate pattern found a year earlier.

4) Two DST's that were taken, one in the SF7-9 and the other in the SF12-5, produced enough water to have the chloride

concentration test. The SF7-9's DST#7 was taken from the U_8 zone. The recovery was 4,982 feet of salty water. Analysis of the sample chamber recovery indicated that the chloride concentration was 36,000 ppm. This concentration is considerably greater than the chloride concentration of the produced water in the SF10-4's present analysis. The SF12-5 DST in the U_6 zone produced 270 feet of water, and analysis of the sample chamber recovery indicated a chloride concentration of 20,000 ppm. The volume recovered in each is enough to eliminate any mud filtrate contamination from the reservoir rock. Also, note that the chlorides in the drilling mud were in excess of 100,000 ppm. Therefore, the chloride concentration in each fluid is considered to be representative of the formations from which they came.

Two conclusions can be made:

1) The water of the U_6 is less salty than the water produced in the SF10-4's present analysis, therefore the water produced from the SF10-4 probably did not come from the U_6 zone.

2) The chloride concentration in the U_8 water is greater than the concentration in both the U_6 and U_4 waters. If the water was coming from the U_8 zone, the chloride concentration should be greater in both of the waters produced from the U_6 and that produced from the U_4.

In light of the preceding arguments, the most likely explanation is that the water down dip from the producers, within the U_4, has greater Na and Cl concentration. Therefore, the water produced from the SF9-9 and SF10-4 is aquifer water, which has been drawn to the perforations by production. With respect to the first argument presented, the R_w's calculated from the intermediate water analyses are considered to be the most likely values for the zone in and around each respective well. As a consequence, these were used in the analysis of the logs for each well.

Wireline Log Calibration

Once an acceptable value for R_w was obtained, the well logs were calibrated against each other to determine if there were any abnormalities. For resistivity calibration the correlatable zone selected was the Stony Mountain Shale, which immediately overlies the Red River Formation. The values of resistivity nearly traced over each other and read 15±2 ohm-m, which was considered to be acceptable consistency.

The bulk density and neutron porosity were then calibrated in several zones. The zones were the identifiable and correlatable shales, anhydrites, limestone, and dolostones of the Bakken, Ashern, Interlake, Stony Mountain, and Red River. Values of neutron porosity and bulk density for each zone, in each well, were compiled, averaged, and adjusted to be within one standard deviation of the average value for the zone.

The bulk density was found to be off consistently in SF8-9, so a constant correction factor of 0.08 gm/cc was added to values read from this well's bulk density log. It should be noted here that this was the only log correction required in all twelve wells.

The first drilling series logs consisted of "old" logs and were not calibrated directly against each other. They consisted of electric surveys, sonic logs, and neutron logs (see Table 6). The electric survey values were assumed to be accurate. The calculated sonic log porosity was compared to the neutron-density porosity of the other wells by means of a compensated sonic porosity log from SF7-9.

The neutron porosity was calculated from the neutron log by a method presented by Hilchie (7). The method consisted of selecting an anhydrite and a shale to provide the maximum separation in the neutron counts. A straight line was drawn between these points when they were plotted on a neutron count versus porosity plot. The shale was taken to be 45 percent porosity and the anhydrite zero.

Since the deep laterologs were run without short-normal laterologs, corrections for bed thickness could not be made. Therefore, the resistivity values from the logs that have been used in the water saturation calculations were considered as an average over 16 feet. The values read from these logs were considered to be inaccurate when they were within 16 feet of the top of the Red River, where the Stony Mountain Shale is located, and were not used.

Wireline Log Analysis

The logs were analyzed by two methods, a "gross section" method and a detailed "foot-by-foot" method. The "gross section" method averages the log parameters over 8 to 20 feet. The detailed or "foot-by-foot" method used smaller distances over which the log parameters were averaged. The distances were limited to the minimum resolution distance the logging tools could read. This method was applied exclusively to the modern logs of the late portion of the first drilling series and the entire second drilling series. The reason for this is that the "old" logs had a resolution distance of approximately 16 feet. This eliminated delineation of beds smaller than 16 feet due to serious boundary effects. The detailed analysis removed the nonporous and nonproductive intervals from the gross section thickness. Upon removal of these nonpay segments, the $So\phi H$ values were reduced, yielding a more accurate estimate of the hydrocarbon pore-volume in the well. The values of the porosity derived from the "foot-by-foot" analysis were compared to actual core porosity values in the following manner.

Core Porosity and Rock Type

Core porosity and rock type were plotted on tracing paper similar to a well log and then correlated to the neutron-density logs. When the values for neutron porosity and density porosity were cross-plotted, the resulting rock type and porosity were checked against the "log of core porosity and rock type" created on the tracing paper, Figure 12. This was done to insure that the most reasonable value of porosity was utilized in each zone. The "log of core porosity" gave a correlation of core permeability to depth. A plot of core permeability versus core porosity from the SF7-9 resulted in a complete random scatter of the data points. Hence, it was concluded that there was no general correlation between core porosity and permeability. However, Friedman, et al. (3) noted that one could be established based on a detailed examination of individual lithofacies. Such an endeavor was beyond the scope of this study.

Water Saturation, S_w

Once the porosity and resistivity values for each zone within the section were obtained, the water saturation (S_w) was calculated from a log-log plot of resistivity versus porosity. This plot has been used extensively for this

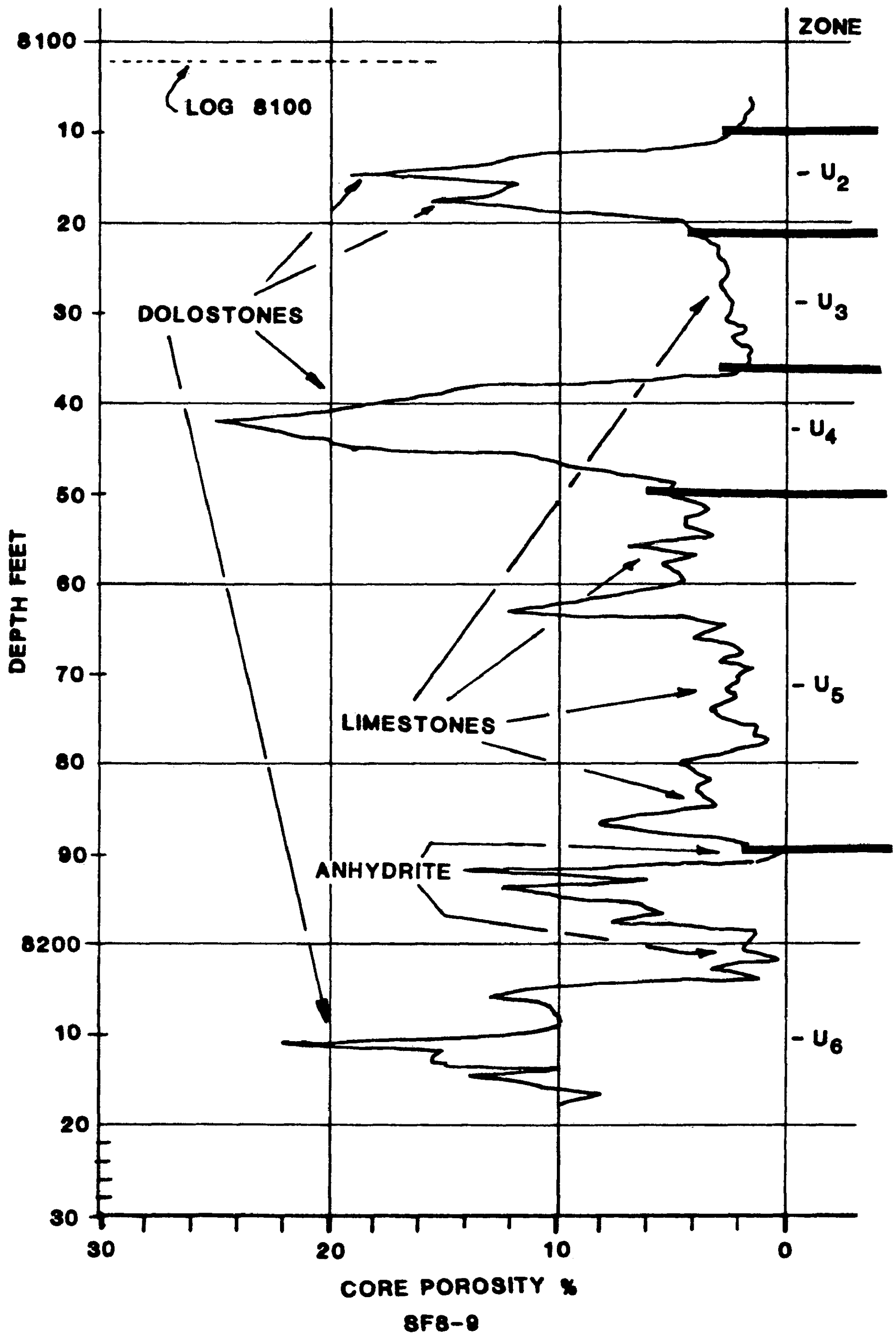

Figure 12. Typical core porosity and rock type plotted versus depth (wireline log format).

purpose; reference 1 has utilized it particularly on the Cedar Creek Anticline. The only change in the standard method of utilizing the plot was to place the slope, derived from the plotted data, through the known value of R_w, calculated from the water analysis. Stated mathematically, given a point and the slope of a line, the line is defined. This line was taken to be the 100 percent water saturation line for the well.

The lower saturation lines (i.e., 90%, 80%, etc.) were calculated from the desired value of S_w and a known R_w. The transformation equation that is required is:

$$R_{to} = R_t \, S_{wo}^{-n}$$

$$n = \frac{\log R_t + m \log \phi - \log R_w}{\log 100.0} ,$$

where R_w = known water resistivity from chemical analysis,

R_{to} = resistivity at the desired S_w,

R_t = known value on the $S_w = 100$ percent line at a given porosity,

S_{wo} = desired value of water saturation,

m = slope of the $S_w = 100$ percent line, lithologic exponent,

n = water saturation exponent, and

ϕ = porosity from which R_w was selected.

This equation gave a series of points, R_{to}, through which parallel lines to the $S_w = 100$ percent line were drawn. Saturations were then read for the corresponding porosity-resistivity combination from the logs. Sample calculations can be found in Appendix B.

To verify the accuracy of the log-log derived water saturations, a second method was investigated. This method was the apparent water resistivity (R_{wa}) approach. The method consisted consisted of calculating the formation resistivity (F_R) from:

$$F_R = \frac{1}{\phi^2} ,$$

which is valid for carbonate rocks (5). The values for ϕ were derived from the neutron-density and sonic-neutron porosity cross-plots. Using the F_R and the deep resistivity (R_t), the apparent resistivity value was determined by:

$$R_{wa} = \frac{R_t}{F_R} .$$

The smallest value calculated for R_{wa} was selected as the formation water resistivity (R_w). The water saturation was calculated from:

$$S_w = \left(\frac{R_{wa}}{R_w}\right)^{\frac{1}{2}} .$$

The R_w that was determined from the R_{wa} method helped verify resistivity calculated from the chemical analysis of the produced water, which was used in the log-log approach.

The log-log approach used the produced water resistivity in its calculation of the water saturations. This method also utilized a slope (M) that was derived from the cross-plotting of the porosity and resistivity. The value of the slope varied from 1.75 to 2.0, which was considered to be good agreement. The slope used in the R_{wa} approach was held constant at 2.0.

Water saturations calculated by both methods agreed within three to five percent. The variance was considered to be acceptable, considering the inherent inaccuracies found in the porosities utilized from the wireline logs. The net effect on the original oil-in-place calculations was considered to be negligible in light of the small difference in the calculated water saturations.

The same procedure was applied in the Mission Canyon, except that the R_w was taken to be 0.54 ohm-m from the recovery of the SF8-9 DST#1.

In the log analysis, limits were placed on porosity and water saturation. The limits were applied to all of the carbonates in the stratigraphic section. From core analysis done on both the Mission Canyon and the Red River, six percent was chosen as the porosity limit. Pickett and Artus (1) demonstrated that in the Pennel Field a permeability-to-porosity ratio, (K/ϕ), greater than 0.30 md/percent resulted in a 20 percent recovery for 160 acres and a (K/ϕ) ratio less than 0.30 md/percent resulted in a recovery efficiency of less than two percent. In consideration of the permeability found in the Study Field's U_4 zone, a (K/ϕ) ratio of 0.30 md/percent implies a 6.67 percent porosity limit. A sensitivity analysis was performed on the porosity limit, since there was variation among references (1), (3), and (5). The variation was: 1) a four percent limit used by Hilchie (5), which was a general number for all carbonates; 2) approximately a six percent limit used by Pickett and Artus (1), which was a field application in the Pennel Field; and 3) a ten percent limit used by Friedman, et al. (3), which was a microscopic study on individual lithofacies in the Cabin Creek Field.

The sensitivity study consisted of summing the pore volume ($H\phi$) for the limits ten percent, six percent, and four percent in the U_4 zone. The deviation from the six percent limit was chosen as a comparison point for two reasons:

1) The Pennel Field is considered to be an analogy field.

2) Pickett and Artus' paper was an application in a field that has been used as an analog for the Study Field.

The results were:

1) An 8.69 percent deduction in pore volume when the porosity limit was increased from six percent to ten percent.

2) A 12.56 percent increase in the pore volume when the porosity limit was reduced from six percent to four percent.

It should be noted here that the dolostones found in the Red River U_4 zone have a hydrophilic nature, and therefore the water is located primarily in the smallest pore spaces. Hence, associated with the pore volume increase in item 2, the connate water saturation also increased. Therefore, the net gain in hydrocarbon pore volume due to the porosity limit reduction is insignificant. Further, the permeability associated with the four percent values averaged approximately 0.03 md. On the other hand, the reduction in the pore volume associated with the increase in the porosity limit from six to ten percent is more significant, as the crude is located in the larger pore spaces.

As a result of the above discussion, six percent was chosen as the porosity limit. This is compatible with Pickett and Artus (1) and with the above sensitivity study.

The water saturation limit was set at 60 percent. This was a median between the 50 percent value used by Pickett and Artus (1) and the value suggested by Hilchie (5) of 70 percent. Both of these values met the criteria of the operator, based on experience in the Williston Basin.

VOLUMETRIC ORIGINAL OIL-IN-PLACE

The best tool for determining the original oil-in-place (OOIP) is the hydrocarbon pore volume (HPV) map. This map is a combination of the petrophysical analysis, structural interpretation of the field, and production history that was available.

The initial structure map consisted of formation top data only. The SF11-23 was included in the main portion of the field. The $So\phi H$ values were plotted on a well location base map, and contoured to fit this particular structure map. The HPV map was planimetered and the trapezoidal rule applied, resulting in 29,000,000 STBO originally in-place. Utilizing this OOIP and the current cumulative production, the recovery efficiency was determined to be abnormally low.

To insure that the map was reasonable, the OOIP was calculated by a method known to give extremely optimistic results. In this paper, this method is called the "ball-parking" method. A drainage area was assigned to each well, and the $So\phi H$ values from the "gross" log analysis were assumed to be consistent throughout the entire area. The result of the calculation was an OOIP of 11,018,000 STBO. Sample calculations are located in Appendix B, and the results of the entire calculation are in Table 9A for the U_4

Table 9A. "Ballparking" the OOIP by fixed area volumetrics: Red River U_4 zone.

WELL	$\bar{\phi}$ (%)	H (ft)	So (%)	OOIP (MSTB)	NP (STB)	RECOVERY EFFICIENCY (%)	STATUS
SF1-9	18.5	13	81	2,102.7	79,665	3.79	*
SF2-15	16.0	8	56	773.7	7,648	0.99	*
SF3-14	15.4	14	50	1,163.6	7,032	0.60	*
SF4-8	13.3	8	62	712.0	8,978	1.26	*
SF5-5	8.0	8	30	207.2	207	0.10	*
SF6-4	15.0	8	30	388.6	307	0.08	*
SF7-9	20.0	10	54	1,165.7	44,668	3.83	
SF8-9	21.0	10	60	1,360.0	55,997	4.12	
SF9-9	23.0	8	60	1,191.6	34,551	2.90	†
SF10-4	15.9	6	49	504.6	12,301	2.44	†
SF12-5	18.8	8	50	811.7	35,978	4.43	
Total				11,018.0	295,034		

Area = 160 AC

B_{oi} = 1.15

* = Plugged and abandoned

† = Temporarily abandoned

zone and Table 9B for the U_2 and U_6 zones.

The two results are obviously inconsistent; therefore the structure map required some modification. The following additional observations in the data were made:

1) The SF11-23's producing gas-oil ratio (R_p) curve is unlike any of the other current producing wells' R_p curves, which indicates that the oil in the reservoir is below bubble-point pressure. This will be discussed further in the production curve analysis section.

2) Single-shot point seismic data indicated the possibility of the SF11-23 existing in a separate structure. The seismic data that were found had been run on a regional basis and eliminated separation of the SF11-23 from the main structure by a fault.

3) Friedman, et al. (3) also noted that permeability variations occur frequently in the Red River. These changes are due to local alteration in the Eogenic cycle, which controls the

Table 9B. "Ballparking" the OOIP by fixed area volumetrics: Red River U_6 and U_2 zones.

WELL	U_6 $\overline{\phi}$ (%)	U_6 H (ft)	U_6 So (%)	U_6 OOIP (MSTB)	U_6 COMMENTS	U_2 $\overline{\phi}$ (%)	U_2 H (ft)	U_2 So (%)	U_2 OOIP (MSTB)
SF1-9	14.0	14	49	1,036.3	DST's np	14.0	10	57	831.2
	19.0	10	45	922.9					
SF2-15	11.3	3	60	219.5		10.6	4	*	
	14.7	*	*	*					
	15.3	10	45	743.2					
SF3-15	**					11.2	6	*	
SF4-8	**					**			
SF5-5	**					9.0	3	*	
SF6-4	11.3	*	*	*		**			
	14.0	*	*	*					
SF7-9	11.8	12	50	764.2	DST's np	5.5	2	*	
	15.5	*	*	*					
SF8-9	9.5	6	61	375.3	DST's np	13.4	4	*	
SF9-9	6.5	6	61	375.3		9.3	2	*	
	10.5	*	*	*					
	18.0	*	*	*					
SF10-4	11.8	*	*	*		5.7	3	*	
SF11-23	6.1	*	*	*		6.1	4	*	
	8.5	*	*	*					
	11.7	*	*	*					
SF12-5	13.0	8	48	538.8	DST's np	15.3	3	*	
	8.5	*	*	*					
	13.8	*	*	*					
	16.5	*	*	*					
Total				4,600.0					831.2

* = <60% S_w
** = <6% ϕ

A = 160 Ac
B_{oi} = 1.15 R_b/STB

np = nonproductive

anhydrite plugging and the porosity development.

All three reasons combine to form a situation which isolates the SF11-23 from the main body of wells in the Study Field. As was hinted at in the discussion on water patterns and will be further discussed in the pressure analysis and material balance sections, a substantial natural water drive exists and should show an effect on the SF11-23. However, this effect is nonexistent, which tends to support the permeability barrier notion, and the isolation of the SF11-23.

As a consequence of the above observations, the structure map was altered. The oil-water contact was changed and the $S_o\phi H$ values were recontoured. The trapezoidal rule was reapplied, resulting in an OOIP of 4,288,000 STBO, for the main structure. This was considered to be more accurate, and was the best estimate of the OOIP. The HPV map is in Figure 13.

Potential in the Mission Canyon was found in three of these wells: the SF8-9, the SF9-9, and the SF12-5. The rest of the wells were either tight by the porosity cut-off or did not develop enough oil saturation to be considered net-pay. The logs of the SF8-9 could not be analyzed due to borehole enlargement which nullified the accuracy of the pad-type log devices. This well, however, was DST'd in the Mission Canyon, and from the water recovery the R_w was estimated to be 0.54 ohm-m at 176°F. The R_w was used in the analysis of the other two wells' wireline logs. Listed below are the results of the analyses:

Table 9C. "Ballparking" the OOIP by fixed area volumetrics: Mission Canyon.

WELLS	POROSITY ϕ, %	HEIGHT H, ft	OIL STRN So, %	EST.* OOIP STBO	EST. SoϕH FROM THE DETAILED LOG ANALYSIS
SF9-9	21.5	5	45	522,000	0.483
SF12-5	20	7	43	507,000	0.604

*Based on 160 AC drainage area and $B_{oi} = 1.15$ RB/STB.

A structure map of the Mission Canyon, shown in Figure 14, was used to develop the HPV map, which appears in Figure 15. The trapezoidal rule was applied, and the resulting OOIP estimate was 994,500 STBO.

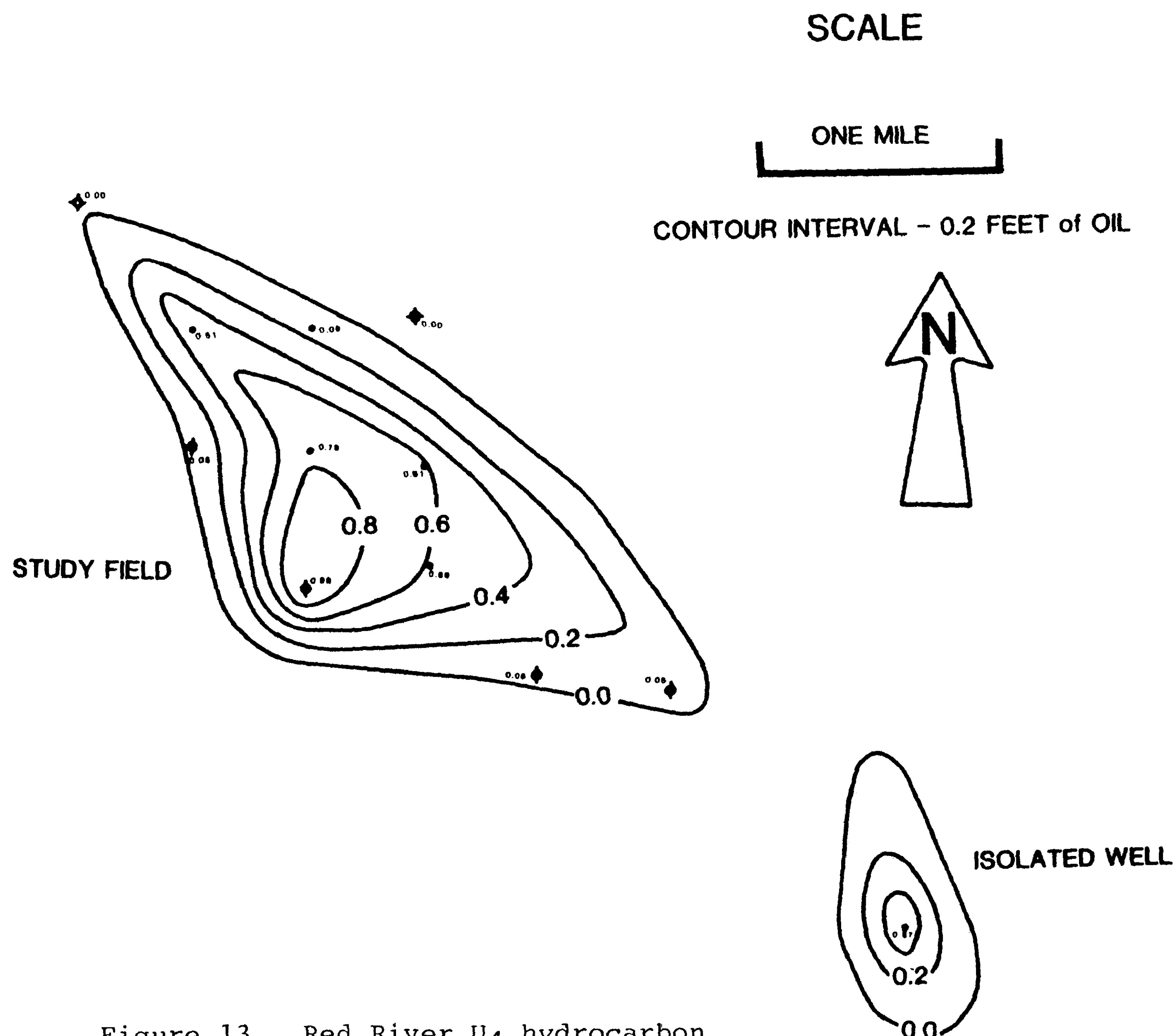

Figure 13. Red River U_4 hydrocarbon pore volume map.

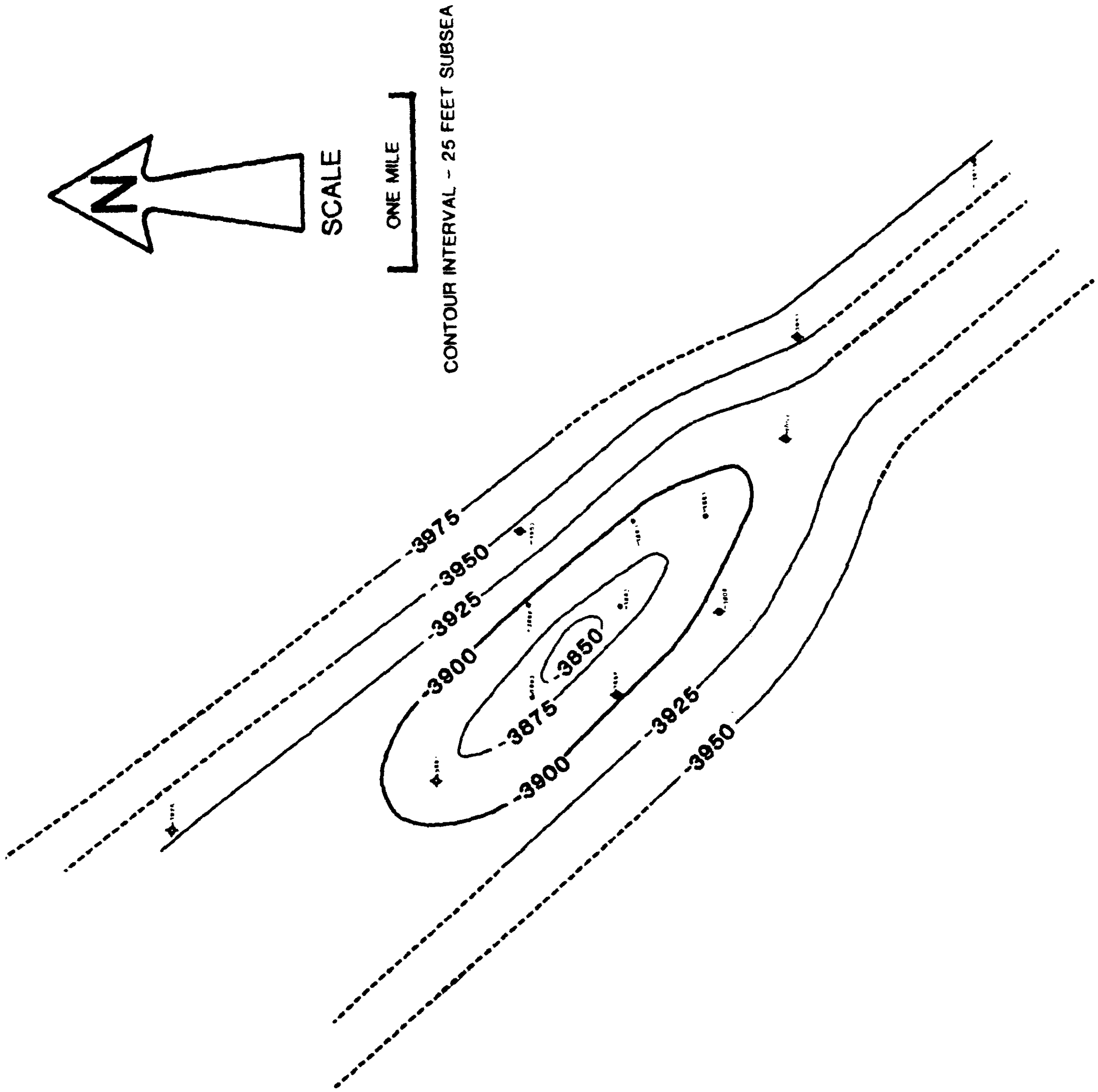

Figure 14. Mission Canyon O_5 structure map.

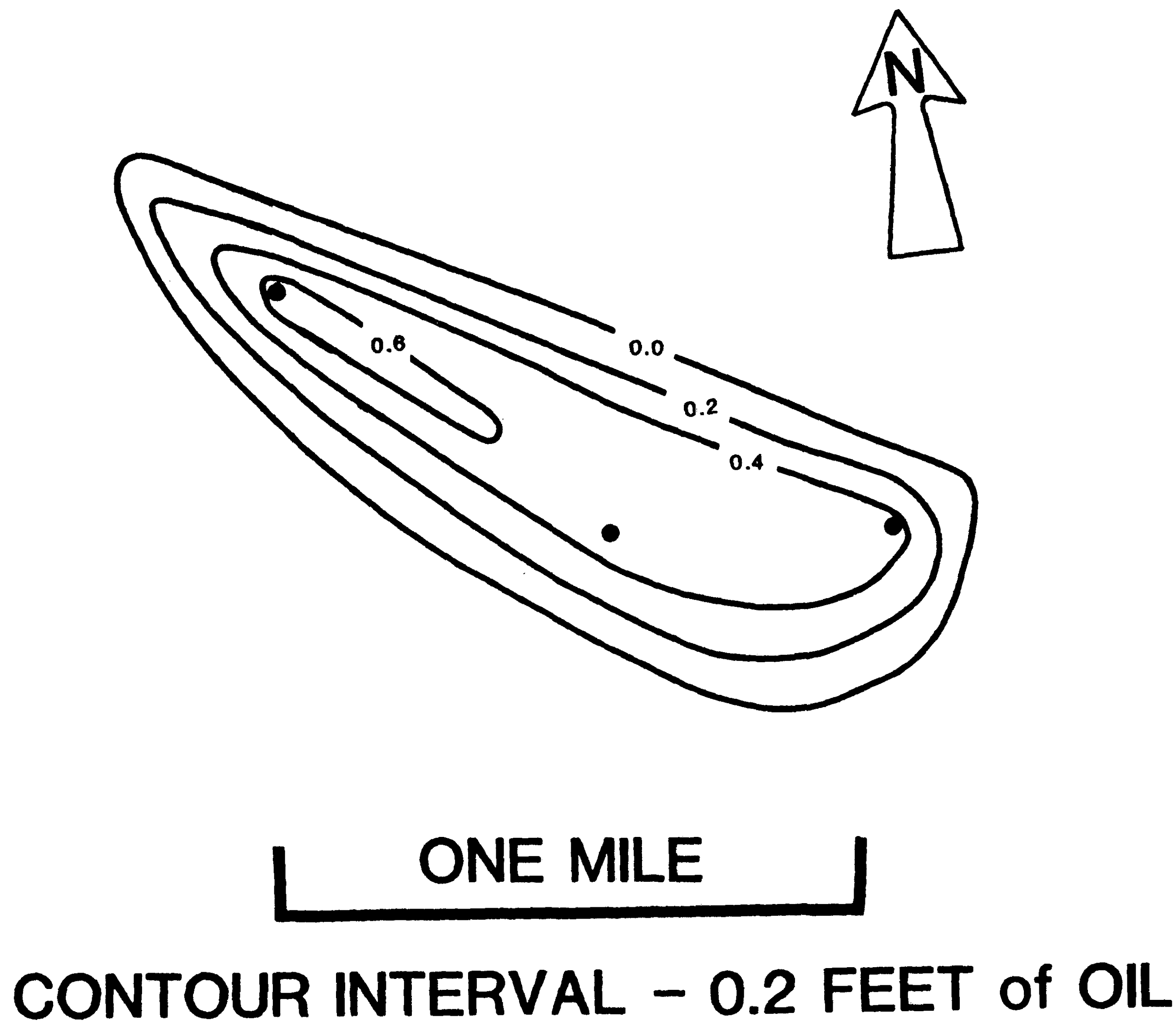

Figure 15. Mission Canyon hydrocarbon pore volume map.

RESERVOIR PERFORMANCE

The reservoir performance of the Study Field was analyzed through three means: reservoir pressure analysis, material balance calculations, and production decline curve analysis. The following section concerns itself with pressure analysis.

Pressure Analysis

In the first drilling series the Red River was DST'd in four wells: the SF1-9, the SF2-15, the SF3-15, and the SF6-4. The DST from the SF6-4 was not analyzed because the the bottom-hole pressure (BHP) time data were not available. The bottom-hole pressure-time data of the other three wells were supplied by Roger Hoeger, a consulting hydrologist who works in the Rocky Mountain region. These tests were analyzed for initial reservoir pressure, where possible.

In the second drilling series all of the DST information was available for analysis. Two wells had enough oil recovery to be completely analyzed for reservoir parameters. These were DST#5 from the SF7-9 and DST#2 from the SF8-9. Both were analyzed by the Horner plot, utilizing the Horner variable (HV) and the Odeh and Selig variable (OSV).

The Odeh and Selig variable and the Horner variable are appropriate for short flow periods, but the OSV method has the advantage of handling rate variation during the test. The method developed by Odeh and Selig was derived to give both the correct flow capacity and initial reservoir pressure. In comparison, the Horner variable gives only the correct initial reservoir pressure (8). The reason for this is that the Horner variable is a first order approximation of the expansion of the exponential integral (E_i) function. The correct solution for short flow periods, as in DST's, requires a second order approximation for the E_i function. Odeh and Selig stated that considerable importance should be attached to the data points approximately within the range:

$$2 > \log[\frac{t^{*}+\Delta t}{\Delta t}] \geq 1.$$

This corresponds to the restriction placed on the expansion of the E_i function, otherwise the method is invalid.

Odeh and Selig further stated that the shut-ins should be at least 1½ times as long as the flow periods. In analyzing the DST's from the first drilling series, all of the final shut-ins were less than 1½ times the flow period. This was common practice at the time that these DST's were run. As a consequence, when the DST's were analyzed, the flow capacities were not calculated. However, the Horner plot was extrapolated, once the correct straight line was found, to the initial reservoir pressure.

From most of the old DST's, the bottom-hole pressure-time trace was converted to pressure-time tables and plotted on the Horner plot. Table 10 summarizes the extrapolated pressures, as well as the analysis completed on the wells in the second drilling series. Table 11 summarizes fluid recoveries, the zone tested, and the depth of each test. A set of sample calculations for Table 10 is shown in Appendix B. In Table 10 the extrapolated pressures were converted to gradients for comparison. It should be noted here, as Odeh and Selig predicted, that the initial pressures were the same and that the permeability calculated by their method was greater than the permeability calculated by the Horner method.

The height (H) and porosity (ϕ) were obtained from the wireline log analysis of the particular well. The mobility calculated was oil mobility (K/μ_o), since only oil was produced from each test completely evaluated. The oil mobility was converted to an effective oil permeability using an oil viscosity (μ_o) of 3.26 centipoise (cps). Utilizing mobility, calculations were made for skin factor (S) and for the radius of investigation (R_i). These calculations were done on DST#5 from the SF7-9 and DST#2 from the SF8-9.

Table 10. Drill-stem test analysis results.

WELL	TEST #	P* (psig)	∇P (psig/ft)	SLOPE (M) (psi/cycle)	H (ft)	ϕ (%)	$\frac{KH}{\mu_o}$ ($\frac{md\text{-}ft}{cp}$)	$\frac{K}{\mu_o}$ ($\frac{md}{cps}$)	K_o (md)	SKIN (S)	R_i (ft)
SF1-9	5	?									
	7	3840	.459								
SF2-15	3	3750	.452								
SF3-15	2	3943	.484								
SF7-9	5	3600	.442	**							
†	5*	3600	.442								
	6	3840	.467								
	7[1]	3822	.461								
SF8-9	1	3091	.459								
	2	3888	.479	1140	10	21	5.479	.548	1.787	-.20	18.22
††	2*	3888	.479	1140	10	21	6.285	.629	2.051	-.49	18.95
	3	3888	.477								
SF11-23	3	3870	.458								
SF12-5	1	3876	.470								
Average			0.467								

* = Analyzed by Odeh and Selig method.

† = t_p^* = 93.63 min Q^* = 57.22 RB/D

†† = t_p^* = 113.21 min Q^* = 47.08 RB/D

1 = This DST went essentially static at this pressure.

? = Test could not be evaluated due to short shut-in.

$c_w=5*10^{-6}$ $c_o=7*10^{-6}$ $c_f=4*10^{-6}$

$c_t=13*10^{-6}$ $B_{oi}=1.15$ $\mu_o=3.26$ cps

** = Invalid test.

Table 11. Zones drill-stem tested in the Study Field.
(page 1 of 3)

WELL	DST #	ZONE TESTED	ZONAL DEPTH	SAMPLE CHAMBER CC			PIPE RECOVERY
				OIL	GAS (ft^3)	WTR	
SF1-9	1	M.C.	6855-69				360' SMCW, 3690' WTR, 1500' BRK WTR.
	2	M.C.	7073-99				WTR @ surface in two hrs, q_w=14 BPH, 10000 ppm SALT.
	3	Inter Lake	7992-8012				180' MDYWTR, 900' SW.
	4	R.R. U_2	8189-8211				1050' CUSH, 10' FREE OIL, 34° API, no GAS or WTR.
	5	R.R. U_4	8229-8244				800' GAS, 240' heavy OIL and GAS cut mud.
	6	R.R. U_6	8290-8332				660' S O & G cut muddy WTR.
SF2-15	1	Lodge Pole	7532-7552				Sulphur WTR to surface; q_w=1 BPH.
	2	R.R. U_4	8289-8308				150' GCO, 90' HG & MCO, 90' G & OC MW.
	3	R.R. U_6	8332-8394				95' SOC & WC M, 256' MW.
SF3-15	1	R.R. U_4-U_6	8145-8193				240' OIL, 60' OCM
SF4-8		None					
SF5-5		None					

M.C. = Mission Canyon R.R. = Red River

Table 11. (Page 2 of 3)

WELL	DST #	ZONE TESTED	ZONAL DEPTH	SAMPLE CHAMBER CC OIL	SAMPLE CHAMBER CC GAS (ft^3)	SAMPLE CHAMBER CC WTR	PIPE RECOVERY
SF6-4	1A	Eagle					
	2	Eagle					
	3	Eagle					
	4	R.R. U_4	8268-8302				10' OIL, 190' SO & GCM.
SF7-9	1-4	M.C.	Misruns				
	5	R.R. U_4	8153-8180	2300			495' GC HEAVY OIL, 30' G & OCM. (OIL 28° API)
	6	R.R. U_6	8215-8255			1840	505' MW.
	7	R.R. U_8	8290-8450			2380	651' W & GC M, 4982' GC MW. (36,000 ppm CI RW = .36 ohm-m @ 56°F)
SF8-9	1	M.C.	6750-6773	350		1600	110' OIL, 90' OCM, 3005' OCW. RW = 1.4 ohm-m @ 75°F; CI = 4000 ppm.
	2	R.R. U_4	8110-8158	2000	0.65		122' OCM, 584' HGCO, 30' SWCO.
	3	R.R. U_6	8155-8218		0.2	1410	60'VSOCM, 376' DM.
SF9-9	1	Dakota	3930-3940				30' HDM.

M.C. = Mission Canyon R.R. = Red River

Table 11. (Page 3 of 3)

WELL	DST #	ZONE TESTED	ZONAL DEPTH	SAMPLE CHAMBER CC			PIPE RECOVERY
				OIL	GAS (ft^3)	WTR	
SF10-9		None					
SF11-23	1-2 3	M.C. R.R. U_4	Misrun 8444-8464*				125' DM, 282' SWCOM, 94' O & WC DM.
SF12-5	1	R.R. U_8	8244-8256	30		2000	40' OCM, 180' O & WC MUD, 270' WTR.

M.C. = Mission Canyon R.R. = Red River * = Only successful straddle test.

Pressure gradients, independent of depth, were calculated to facilitate pressure comparisons between the DST's. The gradient calculated from DST#5 for the SF7-9 was 0.442 psi/foot, and from DST#2 for the SF8-9 was 0.479 psi/foot, which is a considerable difference in the same reservoir. Analysis of the DST's surrounding the SF7-9 and the SF8-9 indicates that the U_4 test for the SF7-9 was invalid. Further, when the scale on the Horner plot for the SF7-9 was expanded, the apparent straight line became concave, therefore the extrapolation was invalid. Experience has shown that there is no pressure variation, at a common datum, between the zones in the Red River.

An average datum within the reservoir was taken to be 8,132 feet KB, located halfway between the lowest perforations in the SF7-9 and the highest perforations in the SF8-9. The Red River gradients were averaged, eliminating the SF7-9's U_4 gradient because it was invalid. The resulting average initial reservoir gradient was 0.470 psi/foot. The average reservoir pressure was then calculated to be 3,822 psi. From this, a range of initial reservoir gradients were established. The lowest value was chosen to be 0.442 psi/foot, the highest value was 0.479 psi/foot, and the most likely value was 0.470 psi/foot. This range was utilized to provide a sensitivity study of the initial reservoir gradient variation. The initial reservoir gradient calculated in the SF3-15, 0.484 psi/foot, was considered to be too high, since the ratio of final shut-in time to final flow time was 0.738 and not 1.5. This indicates that the true Horner straight line had not been established, and therefore the gradient was not utilized in the range. The gradient range was converted to a pressure range from 3,594 psi to 3,895 psi by multiplying the gradient range by the average reservoir datum. All subsequent calculations involving initial reservoir pressure honored this pressure range.

The analysis of DST's included calculating a mobility for oil. From this mobility a permeability was calculated using an oil viscosity of 3.26 cps. There was no PVT analysis of crude oil from the Study Field to assist in the analysis of the field. Therefore, the viscosity was obtained, as were many of the fluid properties used in this study, from the analysis of surrounding fields and then compared to various correlations. The data used were from the neighboring Cedar Creek Field and from the Pennel Field, located northwest along the Cedar Creek Anticline. Since the Cedar Creek Field was closest in proximity to the Study Field, its PVT data were utilized as much as possible.

The oil viscosity was compared to correlations developed by Beal (9) and Vasquez and Beggs (10). Beal's correlation gave an oil viscosity at the bubble-point of 1.6 cps, which was nearly the value acquired from the Cedar Creek Field of 1.8 cps. Since an analogy with the Cedar Creek Field was utilized, the 1.8 cps was projected beyond the bubble-point to the average reservoir pressure of 3,822 psig by Vasquez and Beggs' correlation. The resulting viscosity of 3.26 cps was used throughout the rest of the study.

The justification of the use of PVT properties from the Cedar Creek Field can be made in three similarities:

1) The initial reservoir pressure for the Cedar Creek Field was approximately 3,800 psig. As discussed above, the initial reservoir pressure for the Study Field was estimated to be 3,822 psig.

2) The crude oil produced from the Cedar Creek Field was 28° API. An analysis of the Study Field oil was 28° API.

3) The initial solution gas-oil ratio (R_{si}) for the Cedar Creek Field was 262 SCF/STBO. From an analysis of the produced gas-oil ratio versus time plot, the R_{si} for the Study Field was approximately 260 ± 10 SCF/STBO.

Table 1 in Appendix A is a presentation of the PVT properties from the Cedar Creek Field and the Pennel Field. The table contains oil, water, and rock compressibilities (c_o, c_w, c_f), the initial and bubble-point oil formation-volume factor (B_{oi}, B_{ob}), bubble-point pressure (P_b), the solution gas-oil ratios (R_s), as well as the oil viscosity (μ_o).

Permeabilities in Table 10 were calculated from the slope of the Horner plot. As stated in the discussion concerning the DST analysis methods, the slope from the Odeh and Selig variable on the Horner plot was the correct permeability for the test, and was utilized throughout the subsequent calculations. The difference between the permeabilities calculated from the SF7-9 and the SF8-9 can be attributed to the invalidity of the SF7-9.

Both the SF7-9 and the SF8-9 were cored through the Red River U_4. The permeabilities from the core analysis were geometrically averaged for comparison of the DST values.

The method for this was suggested by Craig (11) for heterogenous reservoirs. The resulting averages were 0.522 md from the SF7-9 and 0.686 md from the SF8-9. The core analysis for each core is in Tables 2 and 3 of Appendix A. The core average permeability value represents the matrix permeability, as the usual technique is to take the test sample plug from a section of the core without fractures. The difference between the average core permeability and permeability calculated from the DST analysis is the DST's ability to affect a greater area in the reservoir. The core permeabilities are usually measured on a one-inch diameter by a two-inch long core plug. Since permeability is an integration over space, a single core of this size is not representative of the actual reservoir permeability. For an accurate value of permeability, the sequential summation method must be applied. This requires a plot of pore volumes injected versus pore volumes recovered. This was unavailable from the core analysis, and as a consequence, the sequential summation method was not applied.

Fluid mobilities were also estimated from Darcy's radial flow equation. The reason for this was to demonstrate the significant difference between oil mobility and water mobility. The wells are currently pumped off every day in eight to ten hours; from this, the bottom hole pumping pressure was estimated to be 200 psig. The total average drainage radius was estimated to be 425 feet, which provided a permeability that agreed with the oil permeability calculated from the DST#2 in the SF8-9. The calculations were carried out for each value listed in the initial pressure range. Table 12 contains a listing of the oil mobility and the total fluid mobility, calculated both before and after water breakthrough. Included in Table 12 is a similar calculation for the Mission Canyon O_5 zone for the following reasons: first, the wireline logs were invalidated due to washouts, which eliminated estimation of $S_o\phi H$ values, and second, the DST in the Mission Canyon leveled out too quickly at the average reservoir pressure to allow Horner slope development, from which reservoir parameters are determined.

The Mission Canyon, as indicated by the DST#1 in the SF8-9, can produce a large volume of water. In this case, the formation produced 36 STBW and 1.6 STBO. From this, it was concluded that the Mission Canyon was uneconomic.

The total fluid mobility in Table 12 changed significantly when water broke through to the well bore. This was attributed to two factors:

Table 12. Estimated mobility from production rates, Red River U_4 and Mission Canyon O_5.

RED RIVER U_4

WELL		SF7-9	SF8-9	SF9-9			SF10-4			SF11-23	SF12-15
H	Ft	10	10	8			6			10	8
RATE	STB/D	20	22	20	56*	214*†	9	51†	63*†	4	19
P_i=3895	psig										
K/μ	md/cps	.6151	.677	.769	1.87	7.16	.461	2.27	2.81	0.123	.731
K	md	2.001	2.206	2.507			1.505			0.401	2.382
P_i=3822	psig										
K/μ	md/cps	.627	.691	.785	1.90	7.30	.470	2.32	2.87	0.125	.746
K	md	2.046	2.250	2.557			1.534			0.409	2.429
P_i=3594	psig										
K/μ	md/cps	.670	.736	.837	2.04	7.79	.502	2.48	3.06	0.134	.795
K	md	2.184	2.401	2.729			1.638			0.437	2.593

MISSION CANYON O_5

WELL		SF8-9
H	Ft	10
RATE	STB/D	17.28
P_i	psig	3091
K/μ	md/cps	.465

*After well begins excessive water production.

$B_o = 1.15$ $\quad \ln[\frac{r_e}{r_w}] = 7.0$ (Red River); 4.8 (Mission Canyon).

$P_{wf} = 200$ psi $\quad \mu_o = 3.26$ cps

†Total fluid produced:

	SF9-9 BEFORE	SF9-9 AFTER	SF10-9 BEFORE	SF10-9 AFTER
WATER (STB)	36	200	41	59
OIL (STB)	20	14	10	3

1) The dolomites of the Red River are hydrophilic.

2) The viscosity of oil was 3.26 cps, as discussed above, and the water was 0.38 cps (11). This resulted in a viscosity ratio of 8.56 to 1.

The large difference between the oil and water viscosities was due to the fresh nature of the water. Not only did this reduce the water's viscosity at reservoir temperature, it also caused bio-degradation of the crude oil. When this occurred, the crude's viscosity was significantly increased. All of this contributed to the behavior observed in the Study Field production, and is the reason for the total fluid mobilities calculated in Table 12, showing a four-fold increase in total fluid mobility when water broke through.

The skin factors calculated in Table 10 are insignificant in the SF8-9. A well with a skin factor of -0.20 is neither damaged or stimulated. Since the SF7-9 had an inaccurate test, its values were erroneous.

There were no slope changes in the Horner plot of the SF8-9, thus it can be concluded that within a radius of

18±.5 feet there were no boundaries or impermeable barriers.

The pressure history of the Study Field is sparse. There has not been a pressure build-up test run since the initial DST's were done. A fluid level survey was taken in July 1982 in both the SF9-9 and SF10-4, which had been shut in for six months and 18 months, respectively. In consideration of the length of time that these two wells had been shut in, the pressure which was calculated at the perforations was considered to be the current average reservoir pressure. Since the fluid column has not been pumped out, there is no readily available means to determine the exact nature of the well-bore fluid. However, it is not necessary to know the exact composition if two extreme cases can be applied to cover all possible combinations. Therefore, since the water produced from the reservoir is essentially fresh (s.g. = 1.002), one of the extreme cases was to employ a fresh water column, and the other was an oil column. The weight of the oil that made up the column was taken to be the produced crude's weight. The fluid levels, the pressures calculated from these extreme columns, and a weighted arithmetic average appear in the table on the following page.

Table 13. Fluid level survey results.

WELL	FLUID LEVEL FROM THE SURFACE (ft)	COLUMN HEIGHT (ft)	MAXIMUM PRESSURE (psig) *	AVERAGE PRESSURE (psig) **	MINIMUM PRESSURE (psig) ***
SF9-9	420	7748	3364	3304	2975
SF10-4	331	7892	3403	3367	3011

* Gradient = 0.434 psig/foot

** Gradient = 0.427 psig/foot

*** Gradient = 0.384 psig/foot

The pressures listed above were combined with the initial reservoir pressure range to form all possible pressure combinations that could have existed in the Study Field. These are summarized in the following table.

Table 14. Maximum reservoir pressure range.

PERMUTATION	INITIAL PRESSURE (psig)	PRESENT PRESSURE (psig)	PRESSURE AT DATUM (psig)	PRESSURE DROP (psig)
1	3895	2975	3123	772 (max.)
2	3822	3367	3468	354
3	3594	3403	3529	65 (min.)

The weighted arithmetic average consisted of 85 percent water and 15 percent oil in the column. This was based on the known final production water cut in the SF10-4 just prior to shut-in. Table 14 is further utilized in the next section, which is the material balance calculations.

Material Balance Relationships

Shilthuis (12), in 1936, presented a general material balance relationship (MBE) based on the summation of produced fluids, fluid expansion in the reservoir, formation compaction, and water influx. This relationship is strictly dependent on pressure and is considered to be a point function. This means that the MBE is calculated at arbitrary pressure points independent of the variations between these points. Generally, the MBE is computed at evenly spaced time increments so that it is matched to past reservoir pressure and production performance; future predictions can then be made.

In the Study Field, the reservoir pressure performance has not been measured. The discovery well, SF1-9, had DST's run in the U_4 and the U_8 zones. The procedure for the U_4 test was to open the DST tool, close it for a 30-minute initial shut-in, open the tool for a 240-minute final flow period, and close the tool for 30 minutes for the final shut-in. The pressure-time trace recorded for the initial shut-in during the DST indicated, by the shape, that the U_4 zone had a low permeability. Analysis of the final shut-in was impossible, due to the short duration. It should have been 360 minutes to have met the 1½ times the final flow period criterion.

The U_8 zone was tested by the same procedure, which was analyzable because of the high permeability exhibited. The resulting initial shut-in pressure was 3,826 psig, which extrapolated to 3,840 psig. The pressure-time trace indicated that the U_8 zone had good permeability by climbing quickly to the static reservoir pressure and nearly leveling off. The fluid production from the U_8 DST was 62 STBW and no oil.

The same phenomenon occurred 20 years later in the testing of the SF7-9. DST#5 was run in the U_4 zone, and DST#7 was run in the U_8 zone. Again, the U_4 zone test was of insufficient duration to establish the correct Horner straight line. However, the U_8 zone pressure-time trace indicated good permeability by climbing quickly to static reservoir pressure and leveling off at 3,822 psig. The final shut-in also leveled off at 3,822 psig, and the total production for the test was 76 STBW and no oil. It has been observed by operators and consultants in the area that there are only normal hydrostatic pressure variations between the productive zones, both oil and water, in the Red River. In other words, there are no abnormally pressured or underpressured zones present. Based on this observation, the following conclusion was made: the pressures measured in the U_8 zone for both the SF1-9 and the SF7-9 are very similar to the initial reservoir pressure in the U_4, differing only by hydrostatic head created by one zone existing deeper than the other.

Analysis of surrounding Red River DST's, within the field, supports this conclusion. As in the case of the SF1-9, extrapolation of the bottom-hole pressure-time data in the SF2-15 resulted in an extrapolated pressure of 3,750 psig. In the SF3-15, the resulting extrapolated pressure was 3,943 psig. As discussed in the Pressure Analysis section, the SF3-15 actual initial reservoir pressure probably is slightly lower due to the fact that the correct Horner straight line may not have been established.

In an analogous manner for the SF7-9, the DST's in the SF8-9 were extrapolated to an initial reservoir pressure of 3,888 psig in both the U_4 zone and the U_6 zone. The DST in the SF12-15 had an extrapolated pressure of 3,876 psig in the U_8 zone, and, even though structurally isolated from the main body of wells, the SF11-23 had an extrapolated pressure of 3,870 psig in the U_4 zone.

From the above arguments, two significant conclusions can be made:

1) The initial reservoir pressure in the U_4 zone is 3,820±75 psig, which is a range of 2.6 percent.

2) The production that occurred between the completion of the SF1-9 in the first drilling series, January 1958, and the completion of the SF7-9 in the second drilling series, May 1977, did not alter the extrapolated initial reservoir pressure as it had built back up to the pressure existing in the SF1-9 in 1958. Therefore, the aquifer associated with the Study Field is infinite acting.

The second conclusion is very important in the analysis of the production by the material balance relationships. This further explains the small pressure drop that is indicated by Permutation 2 in Table 14, which is the most likely case.

The size of the aquifer is further supported by the observation that a general pressure gradient exists to the east of the Study Field. This gradient appears to have its source west of the field, and the water motion is toward the east. According to Roger Hoeger (13), the magnitude of the gradient is approximately 250 feet of fresh water, or approximately 110 psig. This gradient has been recognized by other operators in the area, and is known to extend for approximately 60 miles, which is a gradient of 1.833 psi/mile.

Because of the gap in the data of pressure-performance data, the best estimate of original oil-in-place is the HPV map. The error associated with this map is, reasonably speaking, a factor of 2. The map indicated that there was 4,288,000 STBO OOIP for the main portion of the field, which could be as low as 2,144,000 STBO or as high as 8,576,000 STBO. This is a large range. However, consider the current recovery in the main portion of the field. This is 287,000 STBO and 405,000 STBW, which, when converted to a recovery efficiency, would yield a range of 3.3 to 13.4 percent. These values are very poor, even in the best case, when full pressure maintenance is present. Therefore, material balance calculations will only offer a range of OOIP.

Since there is not any definite pressure history on which to build an analysis, the pressure ranges established by the initial reservoir gradients and the fluid level surveys will be used as end points for the MBE calculations. The most likely case in the Study Field, with an infinite acting natural water drive, is complete replacement of fluids that are withdrawn. Since the permeability was calculated at approximately 2.0 md, the aquifer cannot respond immediately to the pressure changes at the well bore. As a consequence, there will be some pressure drop associated with the production. However, if the field is shut in, as it was between the two drilling series, the initial reservoir pressure is regained as though production had not occurred.

The MBE was applied using the initial reservoir pressure range, which was established in the Pressure Analysis section, as the initial point. The final point was fixed at the pressure range created from the fluid level surveys. These values and the pressure drops associated with them are in Table 14 for clarity. The general form of the MBE (10) that was used in the performance calculation is:

$$N(B_t+B_{ti}) + \frac{N\,B_{ti}\,S_{wio}}{1 - S_{wio}}\left(\frac{B_{tw}}{B_{twi}} - 1\right) + \frac{N\,B_{ti}}{1 - S_{wio}}\,C_f(P_i-P)$$

$$+ \frac{G}{5.615}(B_{gc}-B_{gi}) + \frac{G\,B_{gi}}{5.615}\,\frac{S_{wig}}{1 - S_{wig}}\left(\frac{B_{tw}}{B_{twi}} - 1\right)$$

$$+ \frac{G\,B_{gi}}{5.615(1 - S_{wig})}\,C_f(P_i-P)$$

$$= N_p\left[B_o + (R_{cs}-R_s)\frac{B_g}{5.615}\right] + \frac{G_{pc}\,B_{gc}}{5.615} - \frac{G_i\,B_g'}{5.615}$$

$$- (W_e-W_p)B_w - W_i\,B_{wi} \qquad (1)$$

where N = original oil-in-place (STBO),

N_p = cumulative oil produced (STBO),

G = initial gas-cap gas volume (scf),

G_i = cumulative gas injected (scf),

G_{pc} = cumulative gas-cap gas produced (scf),

G_{ps} = cumulative solution gas produced (scf),

W_e = cumulative water influx (STBW),

W_i = cumulative water injected (STBW),

W_p = cumulative water produced (STBW),

c_f = formation compressibility ($psig^{-1}$),

B_t = total oil formation-volume factor (RB/STB),

B_{ti} = initial total oil formation-volume factor (RB/STB),

B_{tw} = total water formation-volume factor (RBW/STBW),

B_{twi} = initial total water formation-volume factor (RBW/STBW),

B_g = gas formation-volume factor (RCF/SCF),

B_{gi} = initial gas formation-volume factor (RCF/SCF),

B_{gc} = gas-cap formation-volume factor (RCF/SCF),

B_g' = injected gas formation-volume factor (RCF/SCF),

B_w = water formation-volume factor (RB/STBW),

B_o = oil formation-volume factor (RB/STB),

S_{wio} = initial water saturation in oil zone (%),

S_{wig} = initial water saturation in gas-cap (%),

R_s = solution gas-oil ratio (RCF/STB),

R_{si} = initial solution gas-oil ratio (SCF/STB),

R_{sw} = solution gas-water ratio (SCF/STB),

R_{swi} = initial solution gas-water ratio (SCF/STB),

R_p = producing gas-oil ratio (SCF/STB),

R_c = cumulative producing gas-oil ratio (SCF/STB),

R_{cs} = cumulative producing solution gas-oil ratio (SCF/STB),

P = reservoir pressure (psia),

P_i = initial reservoir pressure (psia),

$$B_t = (B_o + (R_{si} - R_s) \frac{B_g}{5.615})$$

$$B_{tw} = (B_w + (R_{swi} - R_{sw}) \frac{B_g}{5.615})$$

$$R_{cs} = G_{ps}/N_p$$

$$R_c = (G_{ps} + G_{pc}) / N_p.$$

This equation includes: 1) injected fluids, 2) produced fluids, 3) in-place fluids, 4) all forms of expansion and compaction, and 5) water influx. The pressure cases are referred to by the permutation numbers found in Table 14, and the material balance cases are referred to by case number for clarity.

The MBE can only be applied to the main portion of the reservoir, as the SF11-23 is located within its own structure. The current pressure in the SF11-23 is unknown, because there has not been a pressure build-up run since the initial DST. Therefore, there are no data for a final point for the material balance calculations.

The general material balance relationship that is presented in equation 1 was reduced to a more exploitable form by applying the following conditions:

1) From wireline log analysis and production testing, there is no evidence of a gas-cap, therefore all terms associated with the gas-cap are zero.

2) The Study Field has only been produced on primary production and there has not been any fluid injection, therefore all fluid injection terms are zero.

3) The water that is produced is considered to be unable to produce any gas.

4) The Study Field reservoir is considered to be at least 1,600 psig over bubble-point pressure. From this, all reservoir fluids

are considered to be slightly compressible.

5) The slight pressure drops that exist in the Study Field are small enough to consider the compressibility invariant.

These conditions reduce equation 1 to the following equation:

$$N\, B_{oi}\left[\frac{B_o - B_{oi}}{B_{oi}} + \frac{C_w S_{wio} + C_f}{1 - S_{wio}}(P_i - P)\right] + WeB_w$$

$$= N_p\left[B_o + (R_p - R_{si})\frac{B_g}{5.615}\right] + W_p B_w \qquad (2)$$

where C_f = rock compressibility (psig^{-1}), and
C_w = water compressibility (psig,$^{-1}$).

Equation 2 is the form of the MBE that was used throughout the study.

The following cases are considered for comparison:

Case I: Expansion of oil and water, rock compaction, and the production of oil from the reservoir. Further, no water influx or production was considered.

Case II: This case was the same as Case I, with the addition of water production.

Case III: Based on the HPV map and the estimated OOIP, the approximate water influx was calculated.

Case IV: This case was an estimation of OOIP with the water influx equal to the withdrawals by production.

Case V: This case was the same as Case IV, except that only 85 percent of the fluid withdrawn was replaced by water encroachment.

Along with Case III, the associated energies of the water, oil, and formation were calculated. These were based on a method presented by Pirson (14). The equations utilized are based on the material balance relationship shown in equation 2. This equation is set equal to one by dividing the left-hand side, reservoir volumes, by the production volumes on the right-hand side. These equations are in the form of:

$$E_o = \frac{N(B_o - B_{oi})}{N_p[B_o + (R_p - R_{si}) \frac{B_g}{5.615}]} , \tag{3}$$

$$E_w = \frac{(W_e - W_p)\ B_w}{N_p[B_o + (R_p - R_{si}) \frac{B_g}{5.615}]} , \tag{4}$$

$$E_R = \frac{\frac{N\,B_{oi}}{1-S_{wio}}\,[C_f+S_{wio}C_w](P_i-P)}{N_p[B_o+(R_p-R_{si})\,\frac{B_g}{5.615}]}\,, \tag{5}$$

where E_o = energy from oil expansion (%),

E_w = energy from water influx (%), and

E_R = energy from connate water expansion and formation compaction (%).

These are calculated to describe the energy associated with each of the driving mechanisms in the reservoir.

The results of the five material balance cases are in Table 15. Case I is an impossible case in this reservoir, as water has been produced. However, change from Case I to Case II illustrates the effect of including water production on a closed container, where there is no influx from the aquifer. When water production is included, the calculated OOIP doubles. This is expected when the reservoir is producing twice as much fluid strictly by expansion and compaction. The values in these two cases, across all of the pressure permutations, range from 25 MM STBO to 587 MM STBO. The values are impossible, as the structure could not contain this much oil. This is supported by the wells that were drilled and found to be wet, the SF6-4 and the SF5-5.

Case III, the water influx estimation, indicated encroachment of approximately 766,000 STBW, which was calculated

Table 15. Material balance results.

PERM.	CASE I N(MSTBO)	CASE II N(MSTBO)	CASE III W_e(STBW)	E_O %	E_W %	E_R %	CASE IV N(est) MSTBO	CASE V N(est)85% MSTBO
I	25,071	50,153	738,559	6.46	82.90	10.64	7,248	13,684
II	53,503	108,118	767,855	3.03	91.99	4.99	14,694	28,709
III	290,097	587,226	792,410	0.56	98.52	0.92	78,965	155,210

with 4,288,000 STBO OOIP. The difference between this and the reported produced fluids is 75,000 STB. Since water is neither injected nor accurately tallied, this volume could be easily lost in the production records. Another possible cause of the discrepancy could be that this estimated OOIP from the HPV map is slightly smaller than the actual OOIP. This is caused by the positioning of the original oil-water contact, which could result in 15 to 30 percent error in the estimated value. It is probably a combination of both problems. The water influx that was calculated in this case was utilized in the calculations of Pirson's (14) energy terms. As would be expected, the water energy is inversely proportionate to the size of the difference between the initial and current reservoir pressures. The reason for the increase in the water energy term is due to the reduction in magnitude of the fluid expansion and formation compaction when the pressure difference is reduced.

Cases IV and V demonstrate the effect of decreasing the actual water influx to exactly equal to the total fluid production. This, in effect, raised the amount of oil required to be originally in place. The most likely value of 14,694,000 STBO is too large for the structure to contain and still honor the nonproductive wells. The pressure drop from Case I is unlikely, as this would require the fluid column to be all oil when the fluid level surveys were taken. Considering the total fluid mobility increase when water broke through, the oil-water viscosity ratio of 8.6, and the rate of water production at the time of breakthrough, a total oil column would be impossible. Therefore, the OOIP estimated by Cases IV and V would be unlikely.

From Table 15 and from the above discussion, some conclusions were drawn:

1) The system in which the Study Field is located is definitely not closed to water influx.

2) The estimates of water influx based on the OOIP of 4,288,000 STBO from the HPV map for the main portion of the reservoir are within reason, considering the total current produced fluid.

3) The estimates of OOIP from 100 percent replacement of the total fluid production are unlikely, due to the volume that the structure would be required to hold.

4) The most likely value for the water influx is between 690,000 STBW and 768,000 STBW.

5) The _most_ _likely_ value for OOIP is between 4,288,000 and 6,000,000 STBO, which lies within the error range mentioned earlier. This is based on the invalidity of the estimates of OOIP in Cases IV and V.

A regional and field model are discussed in the next section, Production Decline Curve Analysis. In this set of models, the unpredictable nature of the production and the reason for the high producing water cut will be discussed further.

Production Decline Curve Analysis

Production decline curve analysis can be a useful method of determining reservoir characteristics, predicting future recovery rates, and total recovery efficiency. In this type of analysis the oil, gas, and water production are plotted in the following forms:

1) Log-Linear (Semilog) Plots. This type of plot consists of oil and water rates, producing gas-oil ratio, oil and water cut, and cumulative oil and water production on the log scale; time and cumulative oil production on the linear scale.

2) Linear-Linear (Linear) Plots. This type of plot consists of oil and water cut, and oil and water rate versus time and cumulative production.

3) Log-Log (Log) Plots. These plots consist of oil rate versus time.

Everything listed above, with the exception of time and cumulative production, has been converted to a daily basis. This is done by dividing by the number of producing days to obtain a daily average, then plotting the daily average in the middle of the month. The data for the production curves were obtained from monthly reports which contain oil, water, and gas production, along with the number of producing days. The production plots appear in Appendix C and are based on the monthly reports. Therefore, if any data are missing from the reports, the associated decline curve cannot be generated. This was the case with the produced gas in the first drilling series of the Study Field. In this set of monthly production reports, the gas that was produced was not reported, hence the first six wells in the field do not have producing gas-oil ratio curves. For comparison purposes, typical curves were used to present both sides of the argument throughout the text.

Since the monthly production reports are the source of data for the production decline curves (PDC), any errors in these reports result in a false curve and subsequently cause erroneous analysis. In the Study Field, the water and the produced gas are not sold. However, they are metered after they are separated from the production stream. The gas is used on location or vented. The water is stored in tanks and trucked from location for disposal. With these facts in mind, the decline curves are probably accurate and lead to a valid analysis.

The end of a Study Field well's producing life is indicated by sudden production of uneconomic quantities of water. This behavior can be attributed to four factors:

1) The hydrophilic nature of the carbonate rocks in the Red River;
2) The high oil-to-water viscosity ratio;
3) The strength of the pressure maintenance;
4) The large relative mobility for water as compared to oil.

These factors cause the four-fold increase in total fluid mobility that was discussed in the Pressure Analysis section. The source of the viscosity difference lies in the fresh water flushing of the Red River. When this zone was flushed with fresh water, as indicated by the Water Pattern Analysis, the oil was exposed to biodegradation, which made the oil more viscous and more resistant to flow. This increased the viscosity ratio (μ_o/μ_w), and thereby increased the relative mobility of the water. The flow model that was implied is this: upon discovery, the oil in the reservoir was in hydrodynamic equilibrium; the water was occupying the smallest pores and the oil was located in the largest pores.

Friedman, et al. (3) noted that the pore throat development is very poor in the small pores and that the diameter of these pores is extremely small, thus the permeability is significantly reduced.

When the Study Field was produced, the water existing in the small pores with poor permeability showed a similar decline rate to that of oil. This continued until water from the aquifer pushed the oil out of the best permeability zones. With an 8.6 times smaller viscosity, the water was then produced at a considerably faster rate, as in the SF9-9 water breakthrough. The timing is unpredictable because it is impossible to determine the location of the natural water front at any given time. This is indicated by the semilog plot of water and oil cut versus time in Figure 16 from the SF9-9. An analysis of the same plots from surrounding wells indicates identical behavior to that of the SF9-9. The plots are level until "water out," at which time there is a sharp break in the water-cut curve; this is further described by the regional model.

A regional model involving the entire Cedar Creek Anticline is: the Anticline is known to be plunging to the northwest along the strike. Prior to the current fresh water flushing that has occurred, oil moved up the anticline parallel to the strike. This happened prior to the fresh water flushing because the current gradient would not have allowed oil motion up dip, which is nearly in the opposite direction. In moving up dip, the oil was trapped in the nodes that exist along the anticline and was held in place by hydrodynamic forces. Where the structure was insufficiently developed or not properly situated, the oil merely moved through the structure and on to traps where it could be contained. This is supported by several features that are outstanding about the region:

1) Most of the major fields are situated on the northwest end of the anticline; for example, the Pennel and the Cabin Creek Fields. The Cabin Creek Field will produce over 100,000,000 STBO and the Pennel far more than that.

2) Production from fields in the northwest portion of the Cedar Creek Anticline have low water cuts, some as high as 1,000 STBO per day with small quantities of water.

3) In the exploration of the southeast end of the anticline, oil-stained cuttings cannot be relied upon as indicators of oil productive zones. As has been mentioned before, DST's are required to indicate production due to the fact that oil-stained zones are often water productive. This is attributed to the oil motion up dip along strike. The oil that is found in these cuttings is residual or flushed oil, which is similar to a flooded out reservoir in that the oil is immobile and the water can move.

4) The high water cuts found in the southeast end of the anticline, particularly in the Study Field wells (Figure 16), are attributed to the reservoir's existence in a transition zone. The production from the Buffalo Field, to the southeast of the Study Field, also exhibits high water cuts. Wells farther to the southeast along the anticline are dry and abandoned.

It was further noted that the water cuts existing in the SF1-9 and the SF8-9 are similar in that the oil cut is

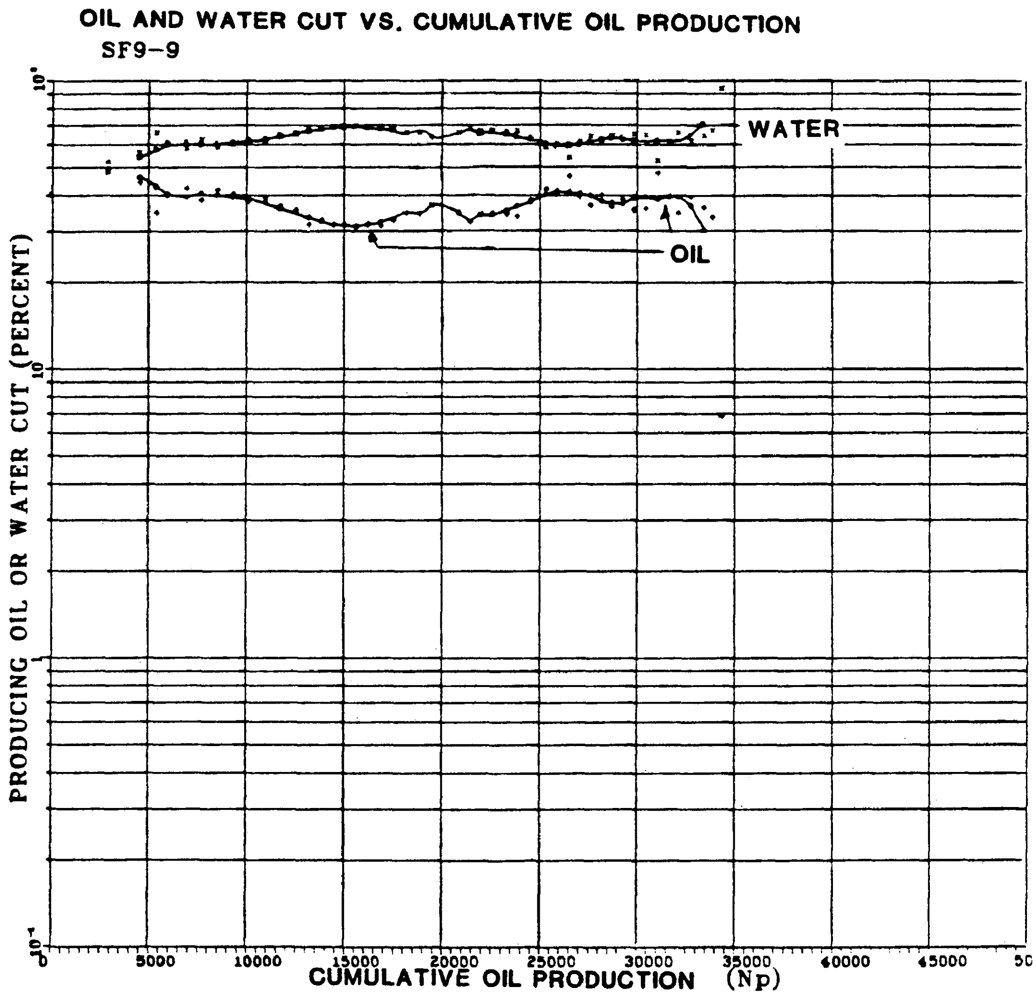

Figure 16. Typical producing gas-oil ratio compared to SF11-23 producing gas-oil ratio.

greater than the water cut. In all of the other wells, the water cut is larger than the oil cut. This indicates a permeability trend between these two wells, which have the two highest cumulative recoveries in the field.

Figure 17 is a typical producing gas-oil ratio (R_p) curve from the wells on the main structure, plotted with the R_p plot from the SF11-23. As has already been noted, the initial solution gas-oil ratio was 260±10 SCF/STBO. The current production rate from the SF11-23 is 2 STBO per day and 7,645 SCF/STBO. This is 29.4 times as much gas as was in solution initially, and indicates that:

1) The area around the SF11-23 is drawn-down below the bubble-point pressure. Obviously, by the amount of gas that is being produced, this would have to be a large area.

2) A comparison of the R_p curve drawn from the data from the SF11-23 to that of the SF8-9 indicates a combination drive system that consists of a weak partial water drive and a solution gas drive. This is further supported by the sharp increase in produced gas-oil ratio to 7,645 SCF/

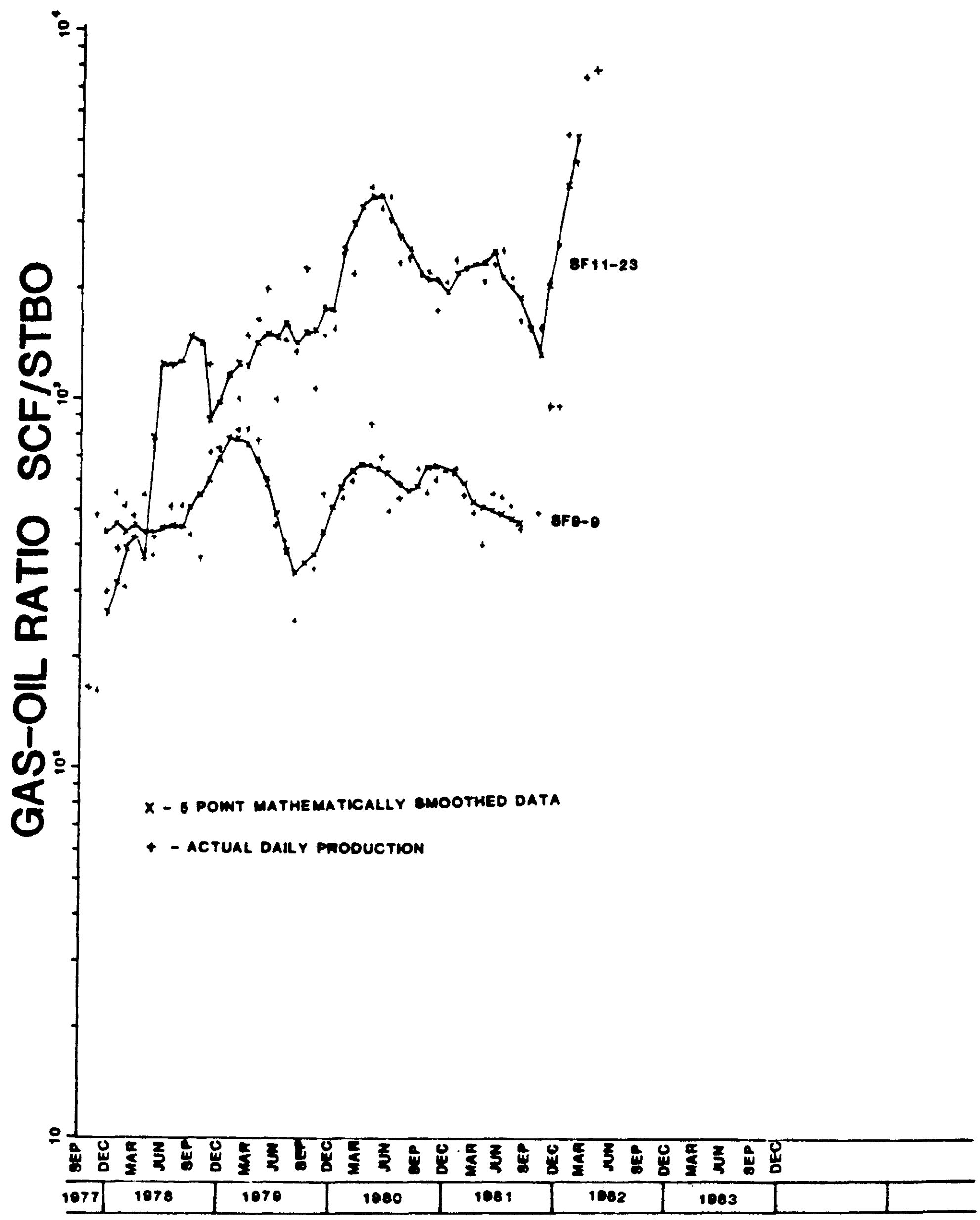

Figure 17. Typical producing gas-oil ratio compared to SF11-23 producing gas-oil ratio.

STBO, along with the water production that is associated with the well's total production.

Therefore, the combination drive system of the SF11-23 is unique to itself with respect to the other wells in the field. In order for this combination drive system to exist in a region that has a strong water drive acting upon it, there must be either fault separation or permeability blockage. The fault separation is discounted due to seismic data that has already been discussed. The permeability blockage is the only reasonable explanation. A strong natural water drive would have caused uneconomic water production as in the SF9-9 and SF10-4.

Another set of interesting plots is from the SF1-9. Figure 18, the semilog plot of oil and water cut versus time, is the only plot of this type that shows the possible effect of the water drive. In this plot, the oil cut remains approximately 97 percent throughout most of the life of the well, then suddenly the oil cut drops and the water cut increases rapidly. There was no production data, in the form of well files, available for this well. Therefore, recompletion operations could not be identified.

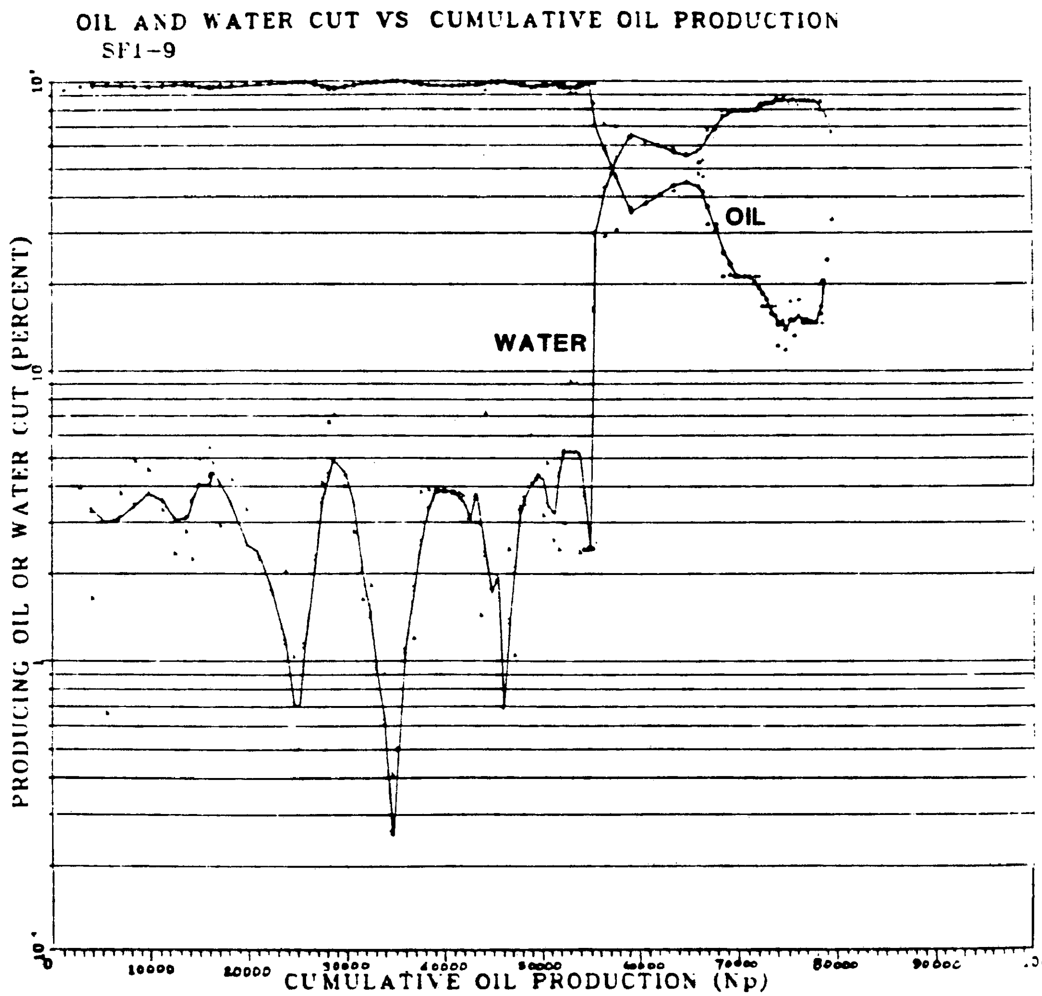

Figure 18. Water cut and oil cut vs.
time for the SF1-9.

Natural causes could not be eliminated, since the water and the oil changed when SF2-15 was drilled and completed. The possibility exists that the well was beginning to produce uneconomic quantities of water in the same fashion as the SF9-9 eighteen years later. This well sets a role model for the SF8-9, which has a similar type of oil- and water-cut plot in that the oil cut is greater than the water cut. When the SF8-9 begins to produce uneconomic quantities of water, it will probably follow the same path as this well.

It is the usual technique to extrapolate the semilog plot or daily oil rate versus time to predict future recovery and rates. In the case of a natural water drive, the extrapolation of the rate curve is replaced by the semilog plot of oil and water cut versus time. It is extrapolated much like a fractional flow curve, and the recovery is determined from a semilog plot of cumulative oil production versus time plot. With respect to the Study Field's curves, neither method is applicable. There are three reasons for this:

1) The strong natural water drive invalidates the rate plot;

2) The horizontal nature of the oil- and water-cut plot;

3) The sudden change that occurs when the wells begin to produce uneconomical water.

This eliminates all of the methods, with any degree of accuracy, for predicting futures.

The next step was to attempt to utilize the API Recovery Efficiency Correlation (15) in hopes that a reasonable recovery efficiency could be calculated. This resulted in a 31.7 percent recovery efficiency, which is high because the Study Field parameters are outside the range of this correlation. Obviously, the 31.7 percent calculated from the correlations is impossible. If all of the three remaining producing wells managed to produce 80,000 STBO, as was produced in the best well, the ultimate recovery would reach 390,000 STBO, resulting in a recovery efficiency of 9.1 percent.

The fourth method that was applied was the least rigorous. In this method the $So\phi H$ values were proportioned with the SF7-9, which had both the best recovery and $So\phi H$ value for the field. Then the proportioned value was multiplied by the recovery from the SF1-9, and the result was taken to be the ultimate recovery from the well. This resulted in the table on the following page (Table 16). Table 16 has an estimated recovery efficiency range of 7.19 to 9.26 percent, and shows recoverable oil remaining in the range of 0.33 to 2.4 percent. With full pressure maintenance, this is extremely poor in both categories. However, the models and the foregoing discussion indicated that this was the case. Also in Table 16, 769,950 STBO was used as the best possible recovery for the wells that were still producing. The reason for this was that the largest $So\phi H$ value was associated with the best recovery, and as a consequence, small $So\phi H$ values are most likely to produce less oil.

Table 16. Estimated ultimate recovery and recovery efficiency.

WELL	$S_o \phi H$ (Ft)	NP (STBO)	ULTIMATE RECOVERY (STBO) MINIMUM	ULTIMATE RECOVERY (STBO) MAXIMUM	REMAINING RESERVES (STBO) MINIMUM	REMAINING RESERVES (STBO) MAXIMUM
SF1-9	0.99	79,665	79,665	79,665	--	--
SF2-15	0.05	7,648	7,648	7,648	--	--
SF3-15	0.05	7,032	7,032	7,032	--	--
SF4-8	0.05	8,978	8,978	8,978	--	--
SF5-5	--	--	--	--	--	--
SF6-4	--	--	--	--	--	--
SF7-9	0.59	44,668	47,477	79,665	2,809	34,997
SF8-9	0.77	55,997	61,962	79,665	5,695	23,668
SF9-9	0.61	34,511	34,511	34,511	--	--
SF10-4	0.086	12,031	12,031	12,031	--	--
SF11-23*	0.50	7,702	8,104	8,104	402	402
SF12-3	0.51	35,978	41,039	79,665	5,061	43,687
Total			308,447+	396,964++	14,237†	102,754††

* The SF11-23 is operating as a combination drive with a very weak partial water drive, resulting in the ultimate semilog rate versus time curve. The decline rate was 16%.

\+ Estimated recovery efficiency = 7.19%.
++ Estimated recovery efficiency = 9.26%.

† Recoverable oil remaining = 0.33%.
†† Recoverable oil remaining = 2.4%.

NOMENCLATURE

B_g	Gas formation-volume factor (RCF/SCF).
B_g'	Injected gas formation-volume factor (RCF/SCF).
B_{gc}	Gas-cap formation-volume factor (RCF/SCF).
B_{gi}	Initial gas formation-volume factor (RCF/SCF).
B_o	Oil formation-volume factor (RB/STB).
B_t	Total oil formation-volume factor (RB/STB).
B_{ti}	Initial total oil formation-volume factor (RB/STB).
B_{tw}	Total water formation-volume factor (RBW/STBW).
B_{twi}	Initial total water formation-volume factor (RBW/STBW).
B_w	Water formation-volume factor (RB/STBW).
c_f	Rock compressibility (psig^{-1}).
c_w	Water compressibility (psig^{-1}).
D & A	Dry and abandoned.
E_o	Energy from oil expansion (%).
E_R	Energy from connate water expansion and formation compaction (%).
E_w	Energy from water influx (%).
G	Initial gas-cap volume (SCF).
G_i	Cumulative gas injected (SCF).
G_{pc}	Cumulative gas-cap gas produced (SCF).

G_{ps}	Cumulative solution gas produced (SCF).
K	Permeability (md).
m	Slope of the S_w = 100 percent line, lithologic exponent.
N	Original oil-in-place (STBO).
N'	Point through which the lower saturation line is drawn.
N_p	Cumulative oil produced (STBO).
n	Water saturation exponent (n is taken to be numerically equal to m).
P	Pressure (psig).
P & A	Plugged and abandoned.
P_i	Initial pressure.
P_{wf}	Well flowing pressure (psig).
R_c	Cumulative producing gas-oil ratio (SCF/STB).
R_{cs}	Cumulative producing solution gas-oil ratio (SCF/STB).
R_i	Radius of investigation (ft).
R_p	Producing gas-oil ratio (SCF/STB).
R_s	Solution gas-oil ratio (SCF/STB).
R_{si}	Initial solution gas-oil ratio (SCF/STB).
R_{sw}	Solution gas-water ratio (SCF/STB).
R_{swi}	Initial solution gas-water ratio (SCF/STB).
R_t	Deep resistivity (ohm-m).
R_w	Water resistivity (ohm-m).

S	Skin factor.
S_{wig}	Initial water saturation in the gas zone (%).
S_{wio}	Initial water saturation in the oil zone (%).
t	Time (min).
z	Gas supercompressibility factor.
ϕ	Porosity.
μ_o	Oil viscosity (cps).
μ_w	Water viscosity (cps).

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APPENDIX A

Well and Field Parameters

The information listed below is for the wells of the second drilling series only, as the well files for the wells in the first drilling series were unavailable.

SF7-9

Current Status:	Pumping 20 STBO, 39 STBW, 721 SCF/STBO.
Spud:	2/77
On Production:	5/77
TD:	8,450
Casing:	1,600' 9-5/8 surface 8,450' 5-1/2 N-80 17#/PPF - 20#/PPF
Cores:	120' - Top of Red River
Completed Zone:	Red River U_4 2 JSPF 8,154'-8,168
Treatments:	(1) 28% HCL acid wash (2) Acid frac.
Artificial Lift:	Sucker rod pump SN @ 8,129'
Surface Equipment:	6' x 27-1/2' treater Pumping unit 3 - 400-barrel oil tanks 1 - 400-barrel water tank

May, 1977: Upon initial completion of this well, the acid fracture broke into underlying water. The water production was excessive, so the well was perforated at 8,300' and a block squeeze was attempted. Water production was still excessive, and it was perforated again at 8,206'. Circulation was established with the perforations at 8,154' - 8,168', with 200 psi, at three quarter barrels per minute, and then squeezed.

This time part of the water was shut off and the well was put on pump.

November, 1977: The water production was still excessive, and the U_4 zone was squeezed off. After a total of 650 sacks of cement, the perforations finally sealed and the pipe could be pressure tested to 1,000 psi. The U_4 zone was perforated and acidized with 2,000 gallons of M.O.D., 15% HCL acid, with a maximum pump pressure of 2,500 psi. The water flow was reduced to half, and the well was again put on pump.

SF8-9

Current Status:	Pumping 20 STBO, 10 STBW, 845 SCF/STBO.
Spud:	5/77
On Production:	8/77
TD:	8,255'
PBTD:	8,200'
Casing:	1,578' 8-5/8 surface 8,255' 5-1/2 N-80 17#/PPF - 20#/PPF
Cores:	8,104' to 8,218' Red River, U_2 through U_6
Completed Zone:	Red River U_4 2 JSPF 8,137' - 8,148'
Treatments:	(1) 28% HCL acid wash (2) Acid frac.
Artificial Lift:	Sucker rod pump SN @ 8,149'

Surface Equipment:	6'-15' treater Pumping unit 2 - 400-barrel oil tanks

The U_6 zone (8,209-8,212, 8,224-8,228, 8,231-8,236) was perforated behind pipe with 4 JSPF and acidized; it swabbed wet. A cement plug was set at 8,200'. The U_4 zone was perforated at 8,137' to 8,148'. It was acidized and acid fractured twice.

SF9-9

Current Status:	T-A
Spud:	8/77
On Production:	10/77
PBTD:	8,240'
Casing:	1,621' 8-5/8 surface 8,300' 5-1/2 N-80 17#/PPF - 20#/PPF
Cores:	None
Completion Zone:	Red River U_4 2 JSPF @ 8,169' - 8,180'
Treatments:	(1) 28% HCL acid wash (2) Acid frac.
Artificial Lift:	Sucker rod pump SN @ 8,150'
Surface Equipment:	Pumping unit

SF10-4

Current Status:	T-A
Spud:	8/77
On Production:	10/77
TD:	8,298'

Casing:	1,555' 8-5/8 surface 8,292 5-1/2 N-80 17#/PPF - 20#/PPF
Cores:	None
Completed Zone:	Red River U_4 2 JSPF 8,173' - 8,185'
Treatments:	(1) 28% HCL acid wash (2) Acid frac.
Artificial Lift:	Sucker rod pump
Surface Equipment:	Tubing, rods, and pump are out of the hole, and pumping unit has been moved off location.

SF11-23

Current Status:	Pumping (uneconomic) 2 STBO, 8 STBW, 7,645 SCF/STBO.
Spud:	7/77
On Production:	10/77
TD:	8,565'
PBTD:	8,542'
Casing:	1,610' 8-5/8 surface 8,565' 5-1/2 N-80 17#/PPF - 20#/PPF
Cores:	8,440' - 8,464' Red River U_4 8,503' - 8,538' Red River U_6
DST's:	Red River straddle test

Recovery:

Depth	Formation	Recovery
8,440-8,464	RR B	94' O&WCM, 125' MUD, 282' WCM w/oil flecks

Completed Zone:	Red River U_4 2 JSPF 8,450' - 8,460'
Treatments:	(1) 28% HCL acid wash (2) Acid frac.
Artificial Lift:	Sucker rod pump SN @ 8,448'
Surface Equipment:	2 - 400-barrel oil tanks 1 - 100-barrel water tank 6'-15' treater Pumping unit

The Lowe Etal 31-23 was acid fractured for a second time, three months after the initial completion, increasing both oil and water production.

SF12-5

Current Status:	Pumping 14 STBO, 22 STBW, 1,100 SCF/STBO.
Spud:	8/77
On Production:	11/77
TD:	8,309'
Casing:	1,555' 8-5/8 surface 8,309' 5-1/2 N-80 17#/PPF - 20#/PPF
Cores:	6,712' - 6,750' Mission Canyon
Completed Zone:	Red River U_4 2 JSPF 8,110' - 8,112'
Treatments:	(1) 28% HCL acid wash (2) Acid frac.
Artificial Lift:	Sucker rod pump SN @ 8,108'
Surface Equipment:	3 - 400-barrel oil tanks 1 - 400-barrel water tank 6'-15' treater Pumping unit

A.1

Analog Data

Table A-1. General analogous data.

From the Cedar Creek Field

Oil gravity = 28° API

$C_f = 4*10^{-6}$ psi^{-1}

$C_w = 5*10^{-6}$ psi^{-1}

$C_o = 7*10^{-6}$ psi^{-1}

B_{oi} = 1.15 RB/STB

B_{ob} = 1.18 RB/STB

P_i = 3,800 psig

P_b = 620 psig

From the Pennel Field

P (psia)	R_s (MCF/STB)
100	0.025
200	0.065
400	0.110
600	0.145
1,000	0.213
1,200	0.235
1,300	0.262
1,500	0.262
2,500	0.262
3,000	0.262
4,000	0.262

Table A-2. Mission Canyon core analysis.

	Depth	Permeability Horizontal	Permeability Vertical	Porosity	Oil Saturation	Water Saturation
VF	6712-6713	31	32	23.1	14.8	77.3
VF	6713-6714	100	111	26.0	30.3	56.4
VF	6714-6715	69	72	26.2	33.2	59.4
VF	6715-6716	74	74	25.7	29.4	65.3
VF	6716-6717	35	39	21.1	18.2	74.6
VF	6717-6718	9.7	6.9	14.5	0.0	98.0
VF	6718-6719	1.4	8.2	10.4	0.0	96.6
VF	6719-6720	0.13	--	6.3	0.0	96.5
VF	6720-6721	2.1	--	11.7	0.0	97.0
	6721-6722	7.1	--	12.6	9.7	87.7
	6722-6723	5.2	--	11.5	4.1	93.6
	6723-6724	8.0	--	11.8	21.4	70.3
VF	6724-6725	10	--	11.8	17.7	64.1
	6725-6726	5.7	--	9.7	12.5	79.3
VF	6726-6727	11	--	10.7	25.5	59.5
VF	6727-6728	0.13	--	10.2	0.0	96.9
	6728-6729	9.7	--	16.2	0.0	97.2
VF	6729-6730	6.9	--	16.7	0.0	97.2
VF	6730-6731	5.2	--	14.9	0.0	90.1
	6731-6732	1.1	--	13.3	0.0	94.3
VF	6732-6733	0.63	--	13.8	0.0	95.5
VF	6733-6734	0.31	--	12.0	0.0	87.1
VF	6734-6735	0.24	--	10.7	0.0	94.6
VF	6735-6736	0.09	--	10.6	0.0	95.1
VF	6736-6737	0.16	--	7.4	0.0	86.9
VF	6737-6738	0.21	--	10.7	0.0	78.0
VF	6738-6739	0.27	--	9.8	0.0	89.9
VF	6739-6740	0.11	--	8.6	0.0	87.2
VF	6740-6741	0.31	--	8.1	1.2	85.0
VF	6741-6742	0.37	--	6.0	1.7	81.1
VF	6742-6743	0.63	--	6.9	1.5	97.2
VF	6743-6744	0.39	--	5.0	2.0	96.4
VF	6744-6745	0.11	--	8.7	1.2	98.1
VF	6745-6746	3.0	--	7.1	1.4	93.7
VF	6746-6747	2.3	--	9.8	1.0	91.9
VF	6747-6748	5.8	--	11.9	0.8	89.1
VF	6748-6749	1.0	--	9.4	1.1	97.0
VF	6749-6750	1.2	--	12.6	1.6	96.0
VF	6750-6751	3.7	--	12.6	1.6	95.6
	Lost foot					

Table A-3. Red River core analysis.
(Page 1 of 2)

Depth	Permeability Horizontal	Permeability Vertical	Porosity	Oil Saturation	Water
8104-8105	No samples				
8105-8106	< 0.01	—	1.6	0.0	66.7
8106-8107	< 0.01	—	1.4	0.0	75.7
8107-8108	< 0.01	—	1.7	0.0	63.9
8108-8109	< 0.01	—	1.9	0.0	69.4
8109-8110	< 0.01	—	2.4	0.0	45.3
8110-8111	< 0.01	—	2.9	0.0	89.3
8111-8112	< 0.01	<.01	4.0	18.7	58.9
8112-8113	.04	.03	12.4	29.8	34.8
8113-8114	.34	.20	12.9	27.0	42.8
8114-8115	1.9	.70	19.2	35.4	27.3
8115-8116	.01	.02	11.8	12.3	45.7
8116-8117	.01	.01	12.5	26.1	42.4
8117-8118	.28	.20	15.4	32.7	25.2
8118-8119	.04	.03	9.3	38.3	27.1
8119-8120	.01	—	4.6	0.0	75.7
8120-8121	< .01	—	4.0	—	82.2
8121-8122	< .01	—	3.5	—	75.6
8122-8123	< .01	—	2.8	—	86.3
8123-8124	< .01	—	2.9	—	59.7
8124-8125	< .01	—	2.5	—	70.2
8125-8126	< .01	—	2.3	—	57.7
8126-8127	< .01	<.01	2.9	18.4	51.4
8127-8128	< .01	—	2.5	—	79.1
8128-8129	< .01	—	2.2	—	77.2
8129-8130	.02	—	2.5	—	60.5
8130-8131	.01	<.01	2.7	19.6	54.8
8131-8132	< .01	—	1.7	0	52.2
8132-8133	< .01	—	2.3	0	64.9
8133-8134	< .01	—	1.4	—	60.7
8134-8135	.01	—	1.5	—	44.2
8135-8136	< .01	—	1.4	—	61.6
8136-8137	< .01	—	2.5	—	85.9
8137-8138	.21	.02	12.3	24.6	31.1
8138-8139	Insufficient sample		15.3	30.8	56.4
8139-8140	5.2	4.7	17.6	37.4	11.0
8140-8141	1.6	1.2	20.3	31.4	33.4
8141-8142	1.0	.86	25.2	29.2	33.2
8142-8143	.70	.55	22.9	32.7	32.7
8143-8144	1.9	1.2	20.0	31.8	35.6
8144-8145	.83	.34	19.5	33.8	36.8
8145-8146	2.1	1.7	11.5	18.6	42.5
8146-8147	.03	.03	9.6	7.5	60.2
8147-8148	.19	.08	6.6	40.0	32.0
8148-8149	2.1	.24	4.8	31.4	53.7
8149-8150	1.1	.18	5.2	24.5	49.0
8150-8151	.07	.03	4.2	12.3	44.3
8151-8152	.03	.02	3.4	22.0	50.2
8152-8153	.06	.01	4.3	17.5	60.0
8153-8154	.07	.01	4.2	12.2	29.4
8154-8155	.52	.18	3.3	15.9	31.9
8155-8156	1.1	.52	7.0	17.8	41.6
8156-8157	.43	.12	3.6	20.3	52.2
8157-8158	.03	.09	5.3	23.4	31.1

ENTIRE CORE HAD VERTICAL FRACTURE

Table A-3. Red River core analysis.
(Page 2 of 2)

	Depth	Permeability Horizontal	Vertical	Porosity	Oil Saturation	Water
	8159-8160	1.4	0.70	2.2	24.4	39.0
VF	8160-8161	10	5.7	6.8	27.3	30.4
VF	8161-8162	1.9	0.13	9.2	32.9	24.1
VF	8162-8163	1.1	0.87	12.4	27.2	12.8
VF	8163-8164	0.68	0.51	4.9	18.7	20.8
VF	8164-8165	0.35	0.21	2.5	29.3	33.5
VF	8165-8166	4.1	3.0	4.0	23.6	31.4
VF	8166-8167	0.09	0.04	2.2	24.0	57.7
VF	8167-8168	0.12	—	1.9	11.5	80.3
	8168-8169	0.12	—	2.8	7.5	60.4
VF	8169-8170	< 0.01	—	1.4	7.6	75.6
VF	8170-8171	0.03	—	2.1	0.0	71.9
VF	8171-8172	< 0.01	—	2.6	8.2	65.6
VF	8172-8173	< 0.01	—	2.0	10.6	42.3
VF	8173-8174	0.03	—	3.4	21.7	55.7
VF	8174-8175	0.01	—	2.6	28.7	49.2
VF	8175-8176	< 0.01	—	1.2	0.0	92.3
VF	8176-8177	< 0.01	—	1.2	0.0	91.6
VF	8177-8178	< 0.01	—	0.5	0.0	83.3
VF	8178-8179	< 0.01	—	2.0	0.0	88.3
VF	8179-8180	0.53	—	4.6	28.1	46.9
VF	8180-8181	0.37	—	3.8	0.0	84.2
VF	8181-8182	< 0.01	—	3.1	0.0	89.9
VF	8182-8183	0.12	—	3.9	0.0	71.5
VF	8183-8184	< 0.01	—	3.2	0.0	95.0
	8184-8185	< 0.01	—	3.0	0.0	91.5
	8185-8186	< 0.01	—	5.4	0.0	96.0
VF	8186-8187	0.12	0.06	8.0	27.9	42.4
VF	8187-8188	0.07	0.01	5.4	32.2	36.2
	8188-8189	< 0.01	—	2.1	0.0	56.5
VF	8189-8190	< 0.01	—	0.3	0.0	70.5
	8190-8191	< 0.01	—	0.5	0.0	80.8
VF	8191-8192	0.78	0.98	14.2	39.2	18.2
VF	8192-8193	0.03	0.01	5.9	29.1	32.7
	8193-8194	0.63	0.12	12.3	43.5	20.1
VF	8194-8195	0.85	0.19	9.9	36.1	17.0
VF	8195-8196	0.40	—	6.0	1.8	71.7
VF	8196-8197	< 0.01	—	5.2	2.1	88.2
VF	8197-8198	0.03	—	7.8	12.4	57.7
VF	8198-8199	< 0.01	—	1.0	0.0	92.0
VF	8199-8200	< 0.01	—	1.5	0.0	93.3
VF	8200-8201	< 0.01	—	1.7	0.0	94.8
	8201-8202	< 0.01	—	0.3	0.0	69.9
	8202-8203	< 0.01	—	3.1	0.0	58.4
	8203-8204	< 0.01	—	1.0	0.0	91.0
VF	8204-8205	0.28	0.15	11.6	33.8	30.3
VF	8205-8206	0.41	0.08	12.6	27.5	32.4
VF	8206-8207	0.08	—	10.3	0.0	76.8

A.2

Petroleum Information Well Data Cards

A) Study Field Wells

1) SF1-9
2) SF2-15
3) SF3-15
4) SF4-8
5) SF5-5
6) SF6-4
7) SF7-9
8) SF8-9
9) SF9-9
10) SF10-4
11) SF11-23
12) SF12-5

B) A well outside the Study Field

SF1-9

```
   FIELD       ELEV     SPC/DIST    DTD     LTD     FM/TD
    5125^    2953 KB               898^            202WNPG


      SPUD               COMPL.         IC        STATUS
    10/27/1957       01/08/1958         WF        OIL
           * * * CASING DATA * * *
 CSG 1^ 3/4 * 18^6 W/ 11^ 5 1/2 * 8311
           * * * INITIAL POTENTIALS * * *
*IPF  195BO                   1^PW
 2^3RDRV  PERF                             8206- 8248 GROSS
 PERF  8206- 8221  8231- 8248
           * * *    TREATMENTS    * * *
 ACID  8206- 8248
 GTY 3^.5
           * * * PI FORMATION TOP DATA * * *
 SPL    6^3NPRR    2188  6^2MDDY    3455  6L2DKOT    3813
 SPL    552PIPR    4577  552PIPP    4695  5^1SPRF    489^
 SPL    452MNKT    5605  419MNLS    5807  353KBBY    628P
 SPL    353CRLS    6392  352MSNC    686^  351LDGP    7183
 SPL    3 6^PRW    7654  2^9SLRN    778^  2^3RDRV    8196
 SPL    2 2WNPG    874^
           * * * CORES * * *
*CORE ^1  6622- 6649 REC 27.0FT 353CRLS
*CORE ^2  6869- 6879 REC 1^.0FT 352MSNC
           * * * FORMATION TESTS * * *
*DST 01       6855- 6869 352MSNC
 REC   360FT  SMCW     369^FT  WTR       15^0FT  BRKW
 INIT OP    4H
*DST 02       7073- 7099 352MSNC
 WTR  TS IN  2H    AT     14 ^WPH
 INIT OP   2H5^M IFP 18^^ FFP 3235
                                      IHP  388^ FHP  39^5
*DST 03       8185- 8211 203RDRV                      S
 REC  1^50FT  CUSH       1^FT  OIL
 INIT OP   4H            FFP  48^
                 FSIP 118^    30M
           * * * PRODUCTION TESTS * * *
*PTF  195BOPD                 1^PW
 2^3RDRV  PERF                            8206- 8248 GROSS
 PERF  8206- 8221  8231- 8248
           * * *    TREATMENTS    * * *
 ACID  8206- 8248   5000GALS
 GTY 30.5
           * * * LOGS AND SURVEYS * * *
 LOGS             ES
```

SF2-15

```
   FIELD      ELEV    SRC/DIST   DTC    LTD    FM/TC
    51250   2924 KB                     8520  203RDRV


      SPUD              COMPL.         IC        STATUS
    10/18/1962      01/22/1963         WC        OIL
            * * * CASING DATA * * *
 CSG  8 5/8 * 1214 W/  5   5 1/2 * 8511 W/  8 L  11 C5
 TBG 2 1/2 AT  8255
            * * * INITIAL POTENTIALS * * *
*IPP   4 BOPD               4 PW
 203RDRV  PERF     BULLT W/  4/FT  8294- 8296        014
            * * *    TREATMENTS    * * *
 ACID  8294- 8296
 QTY 28.0
            * * * FI FORMATION TOP DATA * * *
 LOG    353CRLS   6412  352MSNC   6728  351LDGF   721
 LOG    3 9CVNN   7633  259SLRN   8 10  203GNTN   8 92
 LOG    203RDRV   8246
 SPL    419MNLS   5931  353CRLS   6460  352MSNC   6728
 SPL    351LDGP   7213  2 3SNMN   8 49
            * * * FORMATION TESTS * * *
*DST 01         7532- 7552 351LDGF                   002
               35M IFP 3333 FFP 3541 BHT  188F
             1H    FSIP 3541  1H              FHF  4178
 FLOWED SLI SULFHUR WTR IN 30 MINS AT BPH FOR 5 MIN
*DST 02         8285- 8308 203RDRV                  S003
 REC    150FT  GCO          9 FT  HG?MCC     90FT  G?CCMW
 FINAL OP  2H     IFP   94 FFF  161
 ISIP 3576    45M FSIP 2958  1H
*DST 03         8332- 8394 203RDRV                  S004
 REC     95FT  SOCWCM    256FT  MWTR
               2M
 FINAL CP  2H     IFP   9  FFF  285
 ISIF 3891    45M FSIP 3436  1H    IHF  4654 FHP  4654
            * * * PRODUCTION TESTS * * *
*PTS
 203RDRV  PERF     BULLT W/  4/FT  8334- 8336        006
            * * *    TREATMENTS    * * *
 ACID  8334- 8336    100GALS
 ACID  8334- 8336    500GALS
 ACIDIZED, SWBD 62 BLO, 6 BO CUT 6% WTR ?
 2% PS IN 12 HRS-REACIDIZED
 SWBD 171 BLO, 29 BO CUT 36% WTR IN 10 HRS
 SI, FL * 2000 FT
*PTS    72BO                                      12HRS
```

SF2-15
(cont.)

```
2?3RDPV  PERF                               8334- 8336      0?7
TOTAL RECOVERY ?? BC
*PTS    8?BO                           CUT 25%              21HRS
2?3RDPV  PERF       BULLT W/  4/FT  8294- 8296      0?8
            * * *    TREATMENTS    * * *
ACID  8294- 8296    500GALS
ACID  8294- 8296   5??GALS
RATE   6B/MIN
BRFC  8318- 8318
SET PKR * 8292, ACIDIZED, SWBD 6? BBL
ACID, 43 BO CUT 6% WTR IN 8 HRS
FL * 7???, REACIDIZED
SWBD 17? BLO, 8? BO CUT 25% WTR IN 21 HRS
*PTS  10?BO                            CUT 24%              18HRS
203RDPV  PERF       BULLT W/  4/FT  8266- 8268      009
            * * *    TREATMENTS    * * *
ACID  8266- 8268    5??GALS
ACID  8266- 8268   5??GALS
ACIDIZED ? SWBD 62 BLO, 8 BC IN 3 HRS
REACIDIZED, SWBD 169 BLO, 10? BO CUT 24%
WTR IN 18 HRS
*PTS    3?BO                                                3HRS
203RDPV  PERF                               8266- 8268      01.
*PTS  1??BO                    2??W                         12HRS
203RDPV  PERF                               8266- 8268      011
*PTS    96BO                                                24HRS
203RDPV  PERF                               8266- 8268      012
*PTS    14BO                    ?BW                          3HPS
2?3RDPV  PERF                               8266- 8268      013
RESET PKR * 832?, LOADED HOLE W/WTR ? PUMPED
INTO LOWER PERFS 8334-8336 THRU ANNULUS
W/FULL RETURNS, SET PKR * 835?, PRESS TO
23?? LBS, HELD OK, RESET PKR * 8282 TO
CHK PERFS 8294-8296, PUMPED THRU TBG W/FULL
RETURNS, PULLED PKR ? PLUG, COMMUNICATION
EXISTS BETWEEN ALL SETS OF PERFS
SET RTNR * 836? W/2?? SX, DRLD CMT ? TESTED
ALL PERFS TO 2??? PSI, SET RTNR * 8091 ? SQZD
70 SX ???? ??
203RDPV  PERF       BULLT W/  4/FT  8294- 8296      014
            * * *    TREATMENTS    * * *
ACID  8294- 8296  10?0GALS
RATE 6.5B/MIN                          15% REG ACID
BRFG  8325- 8325
SET PKR * 8276, TAIL PIPE * 8312, ACIDIZED
```

SF2-15
(cont.)

FINAL PRESS 83??, ISI 17??, 15 MIN 15 ?
SWBD 11 BLO 23? BF IN 2? HRS. AV 7 BFPH, 23%
WTR, 12% PS?W, SWPG 7 1/2 BCPH CUT ??% WTR
POP

*PTF 13BO	CUT ?%		2HRS
2??PDRV PERF		8294- 8296	?15
*PTP 123BO	2?BW		24HRS
2??RDRV PFRF		8294- 8296	016
*PTF 52BO	5?BW		24HRS
2??PDRV PERF		8294- 8296	?17
*PTP 43BO	4?BW		24HRS
2??PDRV PERF		8294- 8296	018
*PTF 4?BO	4 BW		24HRS
2??PDRV PERF		8294- 8296	?19
*PTF 40BO	4?BW		24HRS
2??PDRV PERF		8294- 8296	020
*PTF 43BO	4?BW		24HRS
2??PDRV PERF		8294- 8296	?21
*PTF 40BO	4?BW		24HRS
2??PDRV PERF		8294- 8296	022
*PTF 43BO	4?BW		24HRS
2??PDRV PERF		8294- 8296	?23
*PTF 40BO	4?BW		24HRS
2??PDRV PERF		8294- 8296	024

* * * DRILLING HISTORY * * *

MUD TO 852?

SF3-15

```
FIELD        ELEV      SPC/DIST     DTC     LTD     FM/TD
 5125^    2869 KE                  8218             2^3PDRV

   SPUD              COMPL.          IC       STATUS
 ^5/1^/1964        ^8/^6/1964        D        OIL
          * * * CASING DATA * * *
CSG  8 5/8 * 1203 W/  430  5 1/2 * 8215 W/  700  01 04
          * * * INITIAL POTENTIALS * * *
*IPF    558^PD                   6^PW
2^3PDRV  PERF            W/  2/FT  8152- 8183 GROSS 115
PERF  8152- 8154  8181- 8183
          * * *    TREATMENTS    * * *
ACID  8152- 8183
ACIDIZED DETAILS NOT AVAILABLE
          * * * FI FORMATION TOP DATA * * *
LOG   6 2MDDY    3415  602DKOT   3780  552PIPR   4636
LOG   419MALS    5786  353CRLS   6310  352MSAC   6783
LOG   3^ILDGP    71^^  3^9DVN^   7564  259SLRN   7697
LOG   203PDRV    81^7
SPL   552PIPR    4640  452MNHT   5570
          * * * CORES * * *
*CORE  1  814^- 8193 REC 53.^ FT 2^3RDRV          ^02
          * * * FORMATION TESTS * * *
*DST 01        8145- 8193 203R^RV                S003
REC    24^FT  GOIL        6^FT  OCM
FINAL OP  2H     IFP  1^F FFP  136
ISIP 4473        FSIP 34 8    45M
          * * * DRILLING SHOWS * * *
 8145- 8193 2^3PDRV  0?^
          * * * DRILLING HISTORY * * *
MUD  TO  8218
```

SF4-8

```
   FIELD      ELEV    SEC/DIST   DTC    LTD    FM/TD
   51250   2952 KB               8464          203RDRV

      SPUD             COMPL.         IC       STATUS
   10/05/1966    11/24/1966           D        OIL
          * * * CASING DATA * * *
 CSG  8 5/8 ' 1513 W/  550  5 1/2 ' 8461 W/ 1505  01 02
          * * * INITIAL POTENTIALS * * *
*IPP   6 BOPD                  3 BW
 203RDRV  PERF       JET                8244- 8245        00P
          * * *   TREATMENTS     * * *
 ACID  8244- 8245
 QTY 31.0
          * * * FI FORMATION TOP DATA * * *
 LOG   602PCSL   3454  602DKCT   3756  552FIFR   4599
 LOG   5 1SPRF   4865  452MNKT   5585  419MNLS   5760
 LOG   3540TTR   6122  353KEEY   6282  353CRLS   6386
 LOG   352MSNC   67 3  351LDGF   7188  259SLRN   7788
 LOG   203SNMN   8047  203RDRV   8201
          * * * PRODUCTION TESTS * * *
*PTS     BOPH              11BW                      4HRS
 203RDRV  PERF      JET   W/  4/FT  8320- 8337 GROSS 003
 PERF  8320- 8321  8336- 8337
          * * *    TREATMENTS     * * *
 ACID  832 - 8337   1000GALS                 FBRKP 1700
 RATE   1B/MIN                        MAX PR 2500
 SQZD  8320- 8321  8336- 8337               PBTD  8434
 PERF 8320-21, 8336-37, ACIDIZED, DROPPED 6 NYLON
 BALLS, AVG TREATING PRESS 1100 PSI AT 1 BPM, SWBD AVG
 11 BWPH W/TARRY OIL SCUM, SQZD 8320-37 W/75 SX, DRLD
 OUT TO 8282
*PTS    0BO                3BW                       1HRS
 203RDRV  PERF      JET   W/  6/FT  8244- 8245        004
          * * *    TREATMENTS     * * *
 ACID  8244- 8245    500GALS                 FBRKP 1700
 RATE   1B/MIN
 SWBD 11 BF /70% OIL, 30% WTR/
*PTS   25BO               11BW                       1HRS
 203RDRV  PERF                          8244- 8245    005
          * * *    TREATMENTS     * * *
 ACID  8244- 8245   4000GALS                 FBRKP 1800
 RATE   5B/MIN
 ACIDIZED 8244-45 W/4000 GALS 28% ACID, OVERFLUSHED
 W/40 FW, SWBD 36 BF /70% OIL, 30% WTR/, 1 1/2 HRS
*PTS   13BO                7BW                       1HRS
```

SF4-8
(cont.)

```
2̄03RDRV  PERF                          8244- 8245       006
SWBD 2  BF /65% OIL, 35% WTR/, 1 HR
*PTS   11BO                 FEW                        1HPS
203RDRV  PERF                          8244- 8245       007
SWBD 16 BF /70% OIL, 30% WTR/, 1 HR
          * * * LOGS AND SURVEYS * * *
LOGS            LATL                      GRL
LOGS            BSL                       MLAT
LOGS            CALF                      ASL
LOGS            CBND
          * * * DRILLING SHOWS * * *
 8320- 8321 203RDRV  WET    8336- 8337 203RDRV  WET
          * * * DRILLING HISTORY * * *
MUD  TO  8464
```

SF5-5

FIELD	ELEV	SEC/DIST	DTD	LTD	FM/TD
51250	2969 KB		8311	8317	203RDRV

SPUD	COMPL.	IC	STATUS
04/07/1967	06/01/1967	WC	D?A-C

* * * CASING DATA * * *

CSG 8 5/8 " 1672 W/ 660 5 1/2 " 8315 W/ 11[illegible] [illegible]1 02
PULLED 5 1/2 CSG.

* * * PI FORMATION TOP DATA * * *

LOG	603GRNR	2969	602NCSI	3438	602DKOT	3710
LOG	552FIPR	4645	452MNKT	5562	419MNLS	5735
LOG	354OTTR	6115	353KEBY	6275	353CRLS	6383
LOG	352MSNC	6698	351LDGF	7178	259SLRN	7756
LOG	203SNMN	8070	203RDRV	8219		

* * * PRODUCTION TESTS * * *

*PTS 2BFPH CUT 95% 11HRS
203RDRV PERF W/ 4/FT 8235- 8262 GROSS 003
PERF 8235- 8237 8260- 8262

* * * TREATMENTS * * *

ACID 8235- 8262 4 0 GALS FBRKP 8[illegible]
RATE 5B/MIN TP 1800-MAX TP 27[illegible]
ISIP 1800
HAD 1800 FT OIL ? 3800 FT WTR FILLUP IN 12 HRS
*PTS 2BOPH
203RDRV PERF JET W/ 2/FT 8237- 8270 GROSS 004
PERF 8237- 8241 8262- 8270
*PTS 21BF 7HRS
203RDRV PERF 8235- 8270 GROSS 005

* * * TREATMENTS * * *

ACID 8235- 8270 10.00GALS FBRKP 1200
RATE 7.6B/MIN TP 2700
SWBD 21 BF /95% WTR 5% OIL/

* * * DRILLING HISTORY * * *

MUD TO 8311

SF6-4

```
   FIELD       ELEV    SRC/DIST   DTD     LTD    FM/TD
    5125"   2865 KB                      8455  203RDRV


      SPUD              COMPL.          IC       STATUS
    01/01/1963      01/29/1963         WC       D?A-CG
            * * * CASING DATA * * *
 CSG  8 5/8 " 1  4 W/  355                              .3
            * * * PI FORMATION TOP DATA * * *
 LOG    604JDRV     650   604EGLE    1063  603GRNR    2725
 LOG    6 2RKOT    3717   552FIPR    4586  511SPRF    4R 0
 LOG    452MNKT    5536   419MNLS    5681  353CRLSE   6346
 LOG    352MSNC    6561   351LDGF    7451  309DVNN    7644
 LOG    259SLRN    7738   203RDRV    8195
 SPL    351LDGP    7463   309DVNN    7635
            * * * CORES * * *
*CORE  1  8225- 8265 REC 60.0 FT 203RDRV         BLDC 007
*CORE 02  8265- 8302 REC 35.00FT 203RDRV         CSTN 009
*CORE  3  83 2- 834  REC 34.0 FT 203RDRV         CSTN 011
*CORE  1  834 - 837  REC 30.0 FT 203RDRV         OSTN 012
            * * * FORMATION TESTS * * *
*DST 01        1077- 1165 604EGLE                MISRUN 002
                                     PKR FAILED
 WLT 01                                                 002
 RAN WIRELINE DST-NO DETAILS
 AVAILABLE
*DST 1A        1074- 1 74 604EGLE                MISRUN 004
 /2ND RUN/ PKR FAILED AFTER
 2 MIN
*DST212        1074- 1074 604EGLE                MISRUN 005
 /3RD RUN/ PKR FAILED AFTER 5 MIN
*DST 1C        1074- 1 75 604EGLE                MISRUN 006
 REC    100CC  MUD
               40M IFP     0
 ISIP          30M                   IHP    5 5
 NOTE - PKR FAILED AFTER 20 MIN
 OF SI PERIOD
*DST 03        8268- 8302 203RDRV                      S010
 REC     10FT  OIL        190FT  SO?GCM
 INIT OP    2H    IFP  104 FFP  132
                                     BHT  176F
 ISIP 3658    30M FSIP 3228    90M IHF  4504 FHF  4504
 WEAK BLOW, DECR AT END
 180 SLI OCM CONTAINED 4 PERCENT OIL
 24 PERCENT WTR
           * * * DRILLING HISTORY * * *
 MUD  TO  8455
```

SF7-9

FIELD	ELEV	SRC/DIST	DTD	LTD	FM/TD
5125?	2867 KB		8450		203RDRV

SPUD	COMPL.	IC	STATUS
3/22/1977	6/12/1977	D	OIL

* * * CASING DATA * * *
CSG 9 5/8 * 1600 W/ 515 5 1/2 * 8450 01 02
* * * INITIAL POTENTIALS * * *
*IPF 86BOPD 25 BW
203RDRV PERF W/ 4/FT 8154- 8168 0C3
NO TREATMENT REPT
* * * PI FORMATION TOP DATA * * *
LOG 352MSNC 6769 2 3RDRV 8115
* * * LOGS AND SURVEYS * * *

LOGS	CNL	FDC
LOGS	BHC	SONL
LOGS	DILL	GRL

SF8-9

```
   FIELD        ELEV     SRC/DIST    DTD     LTD      FM/TD
    5125^     2872 KB               8255             203RDRV

      SPUD              COMPL.         IC        STATUS
    05/28/1977       08/31/1977        D         OIL
             * * * CASING DATA * * *
CSG  8 5/8 * 1564 W/  7 L  5 1/2 * 8236 W/ 1575  1 C6
TBG 2 7/8 AT  8138
             * * * INITIAL POTENTIALS * * *
*IPF  1''BOPD                         CUT 25%
2'3RDRV  PERF              W/  4/FT  8137- 8146         0C8
             * * *    TREATMENTS     * * *
ACID  8137- 8146
GTY 3'.'' GCR   448
             * * * PI FORMATION TOP DATA * * *
LOG   2'3RDRV   8195
             * * * CORES * * *
*CORE '1  8104- 8129 REC 24.0FT 203RDRV  CONV OIL  002
             * * * FORMATION TESTS * * *
*DST 01        675.- 6773                               S'03
REC  1955CC  OIL       350CC  WTR       16LLCC  WTR
                  IFP  106 FFP  325
                  IFP  367 FFP 1344 BHT  172F
ISIP 3'91        FSIP 3 91        IHP  3475 FHP  3455
                     WC  4'0L FPM CL   RES  1.4'L * 75F 3
NO FORMATION OR TIMES RPTD
NO PIPE REC RPTD
*DST 02        8110- 8158 203RDRV                       S004
REC  2''0CC  OHCG        1CFT GAS
                  IFP   7' FFP  145
                  IFP  102 FFP  291 BHT  186F
ISIP 3663        FSIP 3523        IHP  43'' FHP  4332
NO TIMES RPTD
NO PIPE REC RPTD
*DST 03        8155- 8218 203RDRV                       S005
REC  1410CC  MUD
                  IFP   57 FFP   86
                  IFP   61 FFP  2'' BHT  187F
ISIP 3676        FSIP 3624        IHP  4326 FHP  4353
NO TIMES RPTD
REC .02 CFT GAS, SCUM OF OIL
NO PIPE REC RPTD
```

SF8-9
(cont.)

```
          * * * PRODUCTION TESTS * * *
*PTF   74BOPD               2SPW
 2?3RDPV  PERF          W/  4/FT  8137- 8148        007
          * * *   TREATMENTS     * * *
 ACID  8137- 8148   5000GALS
          * * * DRILLING SHOWS * * *
  8124- 8129 2?3RDRV  OIL
          * * * POROSITY ZONES * * *
  8124- 8129 2?3RDRV  POOR
```

SF9-9

```
   FIELD       ELEV    SEC/DIST   DTD    LTD    FM/TD
    5125"    2865 KB              8312          203PDRV

      SPUD              COMPL.        IC       STATUS
   09/02/1977      10/19/1977         D        OIL
           * * * CASING DATA * * *
CSG  8 5/8 @ 1610 W/  8    5 1/2 @ 8294 W/ 136    1 F2
TBG 2 7/8 AT  8184
           * * * INITIAL POTENTIALS * * *
*IPF   83BOPD                        CUT 529           24HRS
2 3RDRV  PERF             W/  /FT  8169- 818           3
           * * *    TREATMENTS     * * *
ACID  8169- 818    6000GALS
GTY 31.  COR    6
           * * * FI FORMATION TOP DATA * * *
LOG    2 3PDRV   8132
           * * * LOGS AND SURVEYS * * *
LOGS             DILL                       GRL
LOGS             FDC                        CNL
```

SF10-4

```
   FIELD       ELEV     SPC/DIST   DTD     LTD    FM/TD
    5125"    28F2 KB               8312    824f  203RDRV

      SPUD               COMPL.        IC        STATUS
    08/23/1977      10/11/1977         D         OIL
          * * * CASING DATA * * *
CSG  8 5/8 " 1582 W/  81u  5 1/2 " 828  W/ 1376   :1 C2
TBG 2 7/8 AT  8187
          * * * INITIAL POTENTIALS * * *
*IPF   52PfPD                      CUT 5 %            24HRS
2 3RDRV  PERF            W/  2/FT  8173- 8185          0E3
          * * *     TREATMENTS     * * *
ACID  8173- 8185   6000GALS
GTY 31.  GOR   6
          * * * PI FORMATION TOP DATA * * *
LOG   2 3RDRV   8133
          * * * LOGS AND SURVEYS * * *
LOGS             DILL                   GRL
LOGS             FDC                    CNL
```

SF11-23

```
   FIELD      ELEV    SPC/DIST   DTD    LTD    FM/TD
    5125C   3961 KB              8565         203RDRV

      SPUD             COMPL.        IC       STATUS
    7/08/1977     11/10/1977        WC       OIL
          * * * CASING DATA * * *
 CSG  8 5/8 * 1598 W/  740  5 1/2 * 8554 W/ 1359  C1 C5
 TBG 2 7/8 AT  8446
          * * * INITIAL POTENTIALS * * *
*IPF   22BOPD                     CUT 71%           24HRS
 203RDRV  PERF            W/  2/FT  8450- 8460       006
          * * *    TREATMENTS     * * *
 ACID  8450- 8460   6 DOGALS
 GTY 31.0 GOR   470
                               * 60F
          * * * PI FORMATION TOP DATA * * *
 LOG   203RDRV   8410
          * * * FORMATION TESTS * * *
*DST 01      8444- 8464 203RDRV            MISRUN 002
*DST 02      8444- 8464 203RDRV            MISRUN 003
*DST 03      8444- 8464 203RDRV                  S004
 REC  2100CC  SOCM
              IFP   27 FFP  301
               FSIP 3483     IHP  4385 FHP  4390
 NO OTHER TIMES OR PRESSURES RPTD
 NO PIPE REC
          * * * LOGS AND SURVEYS * * *
 LOGS            DILL                    GRL
 LOGS            FDC                     CNL
```

SF12-5

FIELD ELEV SPC/DIST DTD LTD FM/TD
5125 2851 KB 8310 203RDRV

SPUD COMPL. IC STATUS
10/31/1977 12/25/1977 D OIL

* * * CASING DATA * * *

CSG 8 5/8 " 1543 W/ 800 5 1/2 " 8259 W/ 1410 L1 03
TBG 2 7/8 AT 8107

* * * INITIAL POTENTIALS * * *

*IPF 80BOPD CUT 56% 24HRS
203RDRV PERF W/ 2/FT 8110- 8122 004

* * * TREATMENTS * * *

ACID 8110- 8122 6 BBLS
GTY 31.0 GOR 300

* * * FI FORMATION TOP DATA * * *

LOG 203RDRV 8070

* * * FORMATION TESTS * * *

*DST 01 8244- 8256 203RDRV SM02
REC 10FT GAS 2 000CC WTR 3 CC OIL
IFP 32 FFF 220
FSIP 3727 IHP 4456 FHP 4465
NO OTHER DETAILS RPTD
NO PIPE REC RPTD

* * * LOGS AND SURVEYS * * *

LOGS DILL GRL
LOGS FDC CNL

A WELL TO THE NORTH OF THE STUDY FIELD

```
   FIELD       ELEV    SPC/DIST    DTD     LTD     FM/TD
    51250   2950 KB                8525            203PDRV

       SPUD             COMPL.          IC       STATUS
     12/21/1964      3/13/1964          WC       D?A-CG
            * * * CASING DATA * * *
 CSG  8 5/8 @ 1 315 W/  35                             1
            * * * PI FORMATION TOP DATA * * *
 LOG    6 3GRNR    2810  6 2NCSL     3512  552PIPR    4697
 LOG    501SPRF    4340  452MNKT     5634  354CTTR    61
 LOG    353CRLSA   6312  353CPLSP    6419  352MSNC    6650
 LOG    351LDGP    71 6  3 9DVNN     7722  259SLRN    7816
 LOG    2 3SNMN    8116  2 3RDRV     8266
            * * * CORES * * *
*CORE  1  8296- 8357 REC 60.0OFT 203RDRV          ELDC 002
            * * * FORMATION TESTS * * *
*DST 01        8276- 833  203RDRV                      S 03
 REC   181FT  WMLD
 FINAL OP  2H     IFP   38 FFP   81 BHT  174F
 ISIP 3333    30M FSIF 2989  1H30M IHF  4453 FHF  4497
 OPENED W/WEAK BLOW, DIED
 IN 15 MINS, REC WATERY MUD
 W/TRACE OF OIL
*DST 02        8430- 8525 203RDRV                      S 04
 REC  5 40FT  GMCW
 FINAL OP  1H30M IFP  654 FFP 2355 BHT  174F
 ISIF 3447    30M FSIF 3715  2H                  FHP  4536
 STRONG BLOW THROUT
            * * * LOGS AND SURVEYS * * *
 LOGS              GRSL                        LATL
 LOGS              MLAT                        CALP
            * * * DRILLING SHOWS * * *
  8080- 81 0 259SLRN  OSTN   8357- 8525 203RDRV  OSTN
```

APPENDIX B

Sample Calculations

B.1

Wireline Log Calculation

From the well log, after correlation and calibration, the porosity and the associated R_w are plotted on a log-log plot. From the plot, the slope, M, and a point on the line become data in the following calculation:

R_w = 0.10 ohm-m from the water analysis.

From the plot:

$$M = 2.04$$
$$\phi = 9\%$$
$$S_{wo} = 60\%$$
$$R_t = 14 \text{ ohm-m.}$$

1) Calculate the water saturation exponent:

$$n = \frac{\text{Log}(14.0) + 2.04\ \text{Log}(9) - \text{Log}(0.10)}{\text{Log}\ 100}$$

$$n = 1.997$$

2) Calculate the location of any saturation line on the constant ϕ line by:

$$R_{to} = R_t(S_w^{-1.997}),$$

$$R_{to} = (14)(0.6^{-1.997}),$$

$$R_{to} = 0.388 \text{ ohm-m.}$$

With this value and the slope of the 100 percent saturated line, the 60 percent saturation line is defined.

B.2

Original Oil-in-Place Calculation

1) Determination of OOIP by assigned area technique:

$$OOIP = \frac{7758*(1-S_w)*\phi*H*A}{B_{oi}} \text{ BBLS}$$

For SF8-9 from Table 9A:

$H = 10$ feet
$\phi = 21\%$
$S_w = 40\%$
$A = 160$ AC (assigned)
$B_{oi} = 1.15$

$$OOIP = \frac{7758*(1 - 0.40)*0.21*10*160}{1.15}$$

$$= 1{,}360{,}000 \text{ STBO.}$$

2) Recovery efficiency:

$$RE = \frac{N_p}{OOIP} \qquad N_p = 55{,}997 \text{ STBO (from Table 9)}$$

$$RE = \frac{55{,}997}{1{,}360{,}000} * 100 = 4.12\%.$$

3) HPV Calculation:

Trapezoidal Rule

$$V_o = 7758\ \tfrac{1}{2} * C_i * A_o + CI * \sum_{i=1}^{N-1} A_i + \tfrac{1}{2} CI * A_N$$

where CI = contour interval,

A_i = area inside contour i, acres,

A_o = area inside zero contour, acres,

V_o = volume of the oil, BBL.

This rule is applied to an $S_o\phi H$ map, which is contoured in terms of feet of oil. Therefore, the volume calculated from this will yield the OOIP. From the HPV map in Figure 13, the following data was obtained by planimeter:

Contour Interval	Area (AC)
0.9	25.66
0.8	101.32
0.7	218.43
0.6	374.36
0.5	529.63
0.4	756.61
0.3	928.33
0.2	1,138.47
0.1	1,436.24
0.0	1.728.62

$$V_o = 7758*0.1*((\tfrac{1}{2})(25.66) + 101.32 + 218.43 + 374.36 + 529.63 + 756.61 + 928.33 + 1138.47 + 1436.24 + (\tfrac{1}{2})*(1728.62))$$

$$V_o = 4{,}931{,}000 \text{ RB}$$

$$V_{o_{SURF}} = \frac{V_o}{B_{oi}} = \frac{4{,}931{,}000}{1.15} = 4{,}288{,}000 \text{ STBO.}$$

Therefore, there is 4,288,000 STBO in the main portion of the reservoir.

B.3

Drill-Stem Test Calculations

The following data is obtained from DST#2 in the SF8-9:

Drilling Mud Weight:	9.8 lb/gal
Total Depth:	8,158 ft
Packer Depths:	8,104 & 8,110 ft

<u>Pipe Recovery</u>:

Oil Cut Mud:	0.5978 BBL
Heavily Gas-Cut Oil:	2.8616 BBL
Slightly Water-Cut Oil:	0.420 BBL

Initial Hydrostatic	4,299.5 psig
Final Hydrostatic	4,332.1 psig

1) Calculate mud pressure at the bottom packer:

$$PMH = (8110)(0.052)(9.8) = 4,132.8 \text{ psi}$$

$$(1 - \frac{4,132.8}{4,299.5})*100 = 4.03\% \text{ change}$$

$$(1 - \frac{4,132.0}{4,332.1})*100 = 4.82\% \text{ change}$$

% Change < 5% ∴ Probably a good pack-off.

2) From the DST information, it was found that 1.1428 BBL of oil flowed in nine minutes during the first flow period, and 2.7366 BBL of oil flowed during the second flow period in 118 minutes.

$$q_{OIF} = (\frac{1.1438}{9})(1440)$$

$$q_{OIF} = 87.2 \text{ STB}, \ t_p = 9 \text{ min}$$

$$q_{OFR} = (\frac{2.7366}{118})(1440)$$

$$q_{OFR} = 33.40 \text{ STB}, \ t_p = 127 \text{ min}$$

Using the method presented in reference 8:

$$q^* = 47.08 \text{ B/D}$$

$$t^* = 113.71 \text{ min.}$$

3) From the slope of the Horner plot,

M = slope from the Horner plot,

$M_1 = M_{IS} = 3{,}036$ psi/cycle,

$M_2 = M_{FS} = 1{,}140$ psi/cycle,

$M_3 = M_{FS} = 1{,}218$ psi/cycle, and

† = Odeh and Selig variable used in Horner plot.

$$\left.\frac{KH}{\mu_o}\right|_1 = \frac{(162.6)(87.20)(1.15)}{3{,}036} = 5.371 \ \frac{\text{md-ft}}{\text{cps}}$$

$$\left.\frac{KH}{\mu_o}\right|_2 = \frac{(162.6)(1.15)(33.40)}{1{,}140} = 5.479 \ \frac{\text{md-ft}}{\text{cps}}$$

$$\left.\frac{KH}{\mu_o}\right|_3^{\dagger} = \frac{(162.6)(47.08)}{1{,}218} = 6.285 \ \frac{\text{md-ft}}{\text{cps}}$$

ϕ From the logs = 21%

H From the logs = 10 ft

$$\left.\frac{K}{\mu}\right|_1 = 0.537 \text{ md/cps}$$

$$\left.\frac{K}{\mu}\right|_2 = 0.548 \text{ md/cps}$$

$$\left.\frac{K}{\mu}\right|_3^{\dagger} = 0.629 \text{ md/cps}$$

$$c_t = 4*10^{-6} + (0.4)(5*10^{-6}) + 7*10^{-6} = 13*10^{-6}$$

$$S_2 = 1.151\ [\frac{3332.9 - 294.6}{1140} + \log(\frac{2+1}{2})$$

$$- \log(\frac{0.548}{(0.21)(13*10^{-6})(\frac{7.934}{24})^2}) + 3.23]$$

$$= -0.21.$$

$$r_{i_2} = 0.029\ [\frac{(0.548)(118/60)}{(0.21)(13*10^{-6})}]^{1/2} = 18.22 \text{ ft}$$

$$S_3{}^{\dagger} = 1.151\ [\frac{3332.9 - 294.6}{1218} + \log(\frac{1.8952 + 1}{1.8952})$$

$$- \log(\frac{.6285}{(0.21)(13\ 10^{-6})(\frac{7.875}{2})^2}) + 3.23]$$

$$= -0.49.$$

$$r_{d_3}{}^{\dagger} = 0.029\,[\frac{0.0629(113.71/60)}{(0.21)(13.3*10^{-6})}]^{1/2} = 18.95 \text{ ft.}$$

4) Calculations from Darcy's radial flow equation:

In this case, the steady state equation chosen as the aquifer is considered to be infinite acting. Therefore, $\frac{\partial p}{\partial t} = 0$ and the steady state case can be utilized. The inflow equation has the form:

$$P_e - P_{wf} = \frac{141.2 \; q \; \mu \; B_o}{2\pi \; KH} \ln \frac{r_e}{r_w} ,$$

or rearranging in oilfield units:

$$\frac{K}{\mu} = \frac{141.2 \; q \; B_o}{H \; (P_e - P_{wf})} \ln \frac{r_e}{r_w} .$$

Since skin was not considered, r_w was considered to be the well bore radius, and r_e was adjusted to give a mobility equal to the mobility of DST#2 from SF8-9. The resulting r_e was 425 ft. The bottom-hole pumping (P_{wf}) pressure, as indicated in the test, was set at 200 psig. The initial reservoir pressure was varied across the pressure range. For total fluid calculations, the formation volume factor B was assumed equal to 1.0. The error introduced with this assumption was minor with respect to the error introduced when the log term was considered to be the same for all of the wells. Therefore, the calculation for the SF9-9 is:

$$\frac{K}{\mu} = \frac{141.2*56*1.0*7.0}{8*(3895-200)} ;$$

$$\frac{K}{\mu} = 1.872 \frac{\text{md}}{\text{cps}} .$$

5) Viscosity calculation (Vasquez and Beggs (10)) from Beals Correlation, ref. 9:

$$\mu_o = 1.6 \text{ cps} < 1.8 \text{ cps from Cedar Creek Field.}$$

Since this is an analogy, 1.8 cps will be utilized.

$$\mu_{o_{3822}} = (1.8)\left(\frac{3822}{620}\right)^{(2.6)(3822)^{1.187} e^{(-11.513-8.98*10^{-5}(3822))}} ;$$

$$\mu_o = 3.279 \text{ cps @ } 3,822 \text{ psig.}$$

B.4
Material Balance Calculations

Material balance equations are generally looked at in sections or parts. There are the production terms, expansion terms, and compaction terms. In this study, the most useful form of the material balance used was in equation 2:

$$N\, B_{oi}\, [\frac{B_o - B_{oi}}{B_{oi}} + \frac{C_w S_{wio} + C_f}{1 - S_{wio}}\, (P_i - P)] + WeBw$$

$$= N_p [B_o + (R_p - R_{si})\, \frac{B_g}{5.615}] + W_p B_w \qquad (2)$$

This equation can be reduced into the following forms for each case that was considered.

Case I:

$$N\, B_{oi}\, [\frac{B_o - B_{oi}}{B_{oi}} + \frac{C_w S_{wio} + C_f}{1 - S_{wio}}\, (P_i - P)]$$

$$= N_p\, [B_o + (R_p - R_{si})\, \frac{B_g}{5.615}]$$

in which W_p and W_e were set equal to zero;

Case II:

$$N\, B_{oi}\, [\frac{B_o - B_{oi}}{B_{oi}} + \frac{C_w S_{wio} + C_f}{1 - S_{wio}}\, (P_i - P)]$$

$$= N_p\, [B_o + (R_p - R_{si})\, \frac{B_g}{5.615}] + W_p B_w$$

in which $W_e = 0$;

Case III, rearranging equation 2:

$$W_e = \frac{1}{B_w} \{N_p[B_o + (R_p - R_{si}) \frac{B_g}{5.615}] + W_p B_w$$

$$- N\, B_{oi} [\frac{B_o - B_{oi}}{B_{oi}} + \frac{C_w S_{wio} + C_f}{1 - S_{wio}} (P_i - P)]\}$$

(the energy equations are given in the text);

Cases IV and V, rearranging equation 2 again:

$$N = \frac{N_p \; [B_o + (R_p - R_{si}) \frac{B_g}{5.615}] + (W_p - W_e) B_w}{B_{oi} \; [\frac{B_o - B_{oi}}{B_{oi}} + \frac{C_w S_{wio} + C_f}{1 - S_{wio}} (P_i - P)]}$$

where in Case IV, $W_e = W_p$, and in Case V, $W_e = 0.85 * W_p$.

The following equations were also utilized:

$$B_o = B_{oi} \, e^{C_o (P_i - P)} \qquad B_{oi} = 1.15$$

$$B_w = B_{wi} \, e^{C_w (P_i - P)} \qquad B_{wi} = 1.02$$

$$B_g = \frac{Z_R T_r P_s}{T_s P_r}$$

where T_r = reservoir temperature, °R,
P_r = reservoir pressure, psia,
P_s = standard pressure, psia,
T_s = standard temperature, °R,
Z_R = gas supercompressibility factor.

$$S_{wio} = \frac{\sum_{j=1}^{12} S_{wio_j} * H_j}{\sum_{j=1}^{12} H_j} \quad \text{percent.}$$

These, combined with the reservoir parameters, resulted in the following MBE constants and variables:

$$C_o = 2*10^{-6}\ psi^{-1}$$

$$C_w = 5*10^{-6}\ psi^{-1}$$

$$C_f = 4*10^{-6}\ psi^{-1}$$

$$B_w = 1.02\ e^{5*10^{-6}(P_i-P_r)}$$

$$B_o = 1.15\ e^{7*10^{-6}(P_i-P_r)}$$

$$B_g = \frac{0.85*(460+176)*14.7}{520 * P_r} = \frac{15.282}{P_r}$$

$$R_s = R_{si} = 262 \text{ SCF/STBO}$$

$$R_p = \frac{G_p}{N_p} = \frac{107,988*10^3}{183,758} = 588 \text{ SCF/STBO}$$

$$\left.\begin{array}{l} N = 4,288,000 \text{ STBO} \\ N_p = 287,000 \text{ STBO} \\ W_p = 403,899 \text{ STBW} \end{array}\right\} \text{For main reservoir only}$$

$$S_{wio} = 45.63\%.$$

The production term $N_p[B_o + (R_p - R_{si}) \frac{B_g}{5.615}]$ becomes:

$$\alpha = 287{,}000\ [1.15\ e^{7*10^{-6}(P_i - P_r)} + \frac{887.25}{P_r}].$$

The expansion-compaction term $B_{oi}[\frac{B_o - B_{oi}}{B_o} + \frac{C_w S_{wio} + C_f}{1 - S_{wio}}(P_i - P)]$

becomes:

$$\beta = 1.15\ [(e^{7*10^{-6}(P_i - P_r)} - 1) + 1.1553*10^{-5}(P_i - P_r)].$$

The MBE was calculated in segments, as listed above. The sample calculation is presented for Case III, for:

$P_i = 3820$ $\qquad$ $P_r = 3172$

$$P_i - P_r = 3822 - 3468 = 354 \text{ psi.}$$

$$\alpha = 287{,}000[1.15\ e^{7*10^{-6}(354)} + \frac{887.25}{3468}]$$

$$\alpha = 404{,}294\ (RB)$$

$$\beta = 1.15[(e^{7*10^{-6}(354)} - 1) + 1.1553*10^{-5}(354)]$$

$$\beta = 0.00756\ (RB/STB)$$

$$B_w = 1.02\ e^{5*10^{-6}(354)} = 1.0218$$

$$W_e = \frac{1}{1.022} [(404,294) + 403,899(1.022)$$

$$- 4,288,000(0.00756)];$$

$$W_e = 767,855 \text{ (RB)}.$$

Calculation for the energy terms:

$$e_o = \frac{N(B_o - B_{oi})}{\alpha}$$

$$e_w = \frac{(W_e - W_p) B_w}{\alpha}$$

$$e_r = \frac{\frac{N\ B_{oi}}{1 - S_{wio}} [C_f + S_{wio} C_w] (P_i - P)}{\alpha}$$

Substituting:

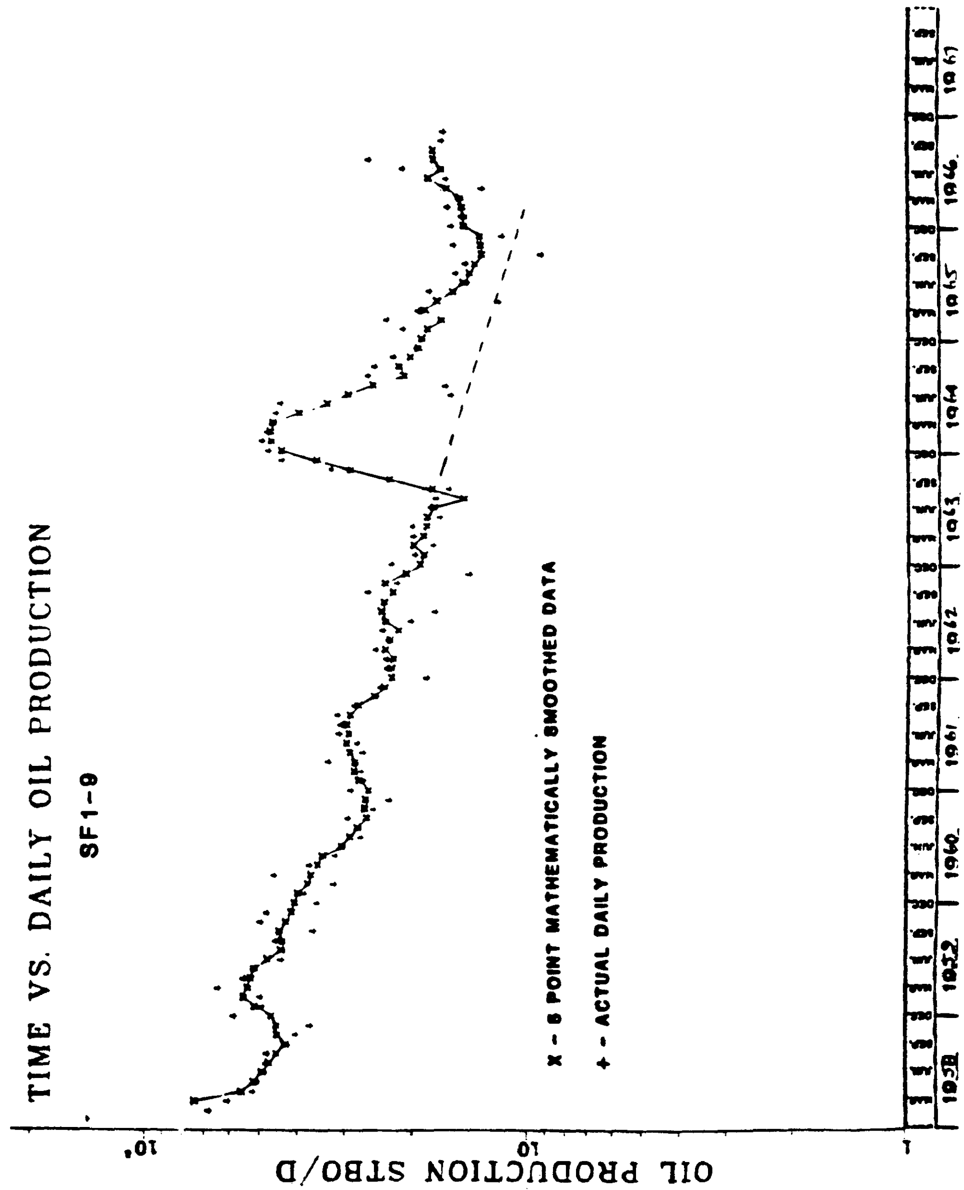
$$e_o = \frac{4,288,000(1.15\ e^{7*10^{-6}(354)} - 1.15)}{404,294} = 0.0303$$

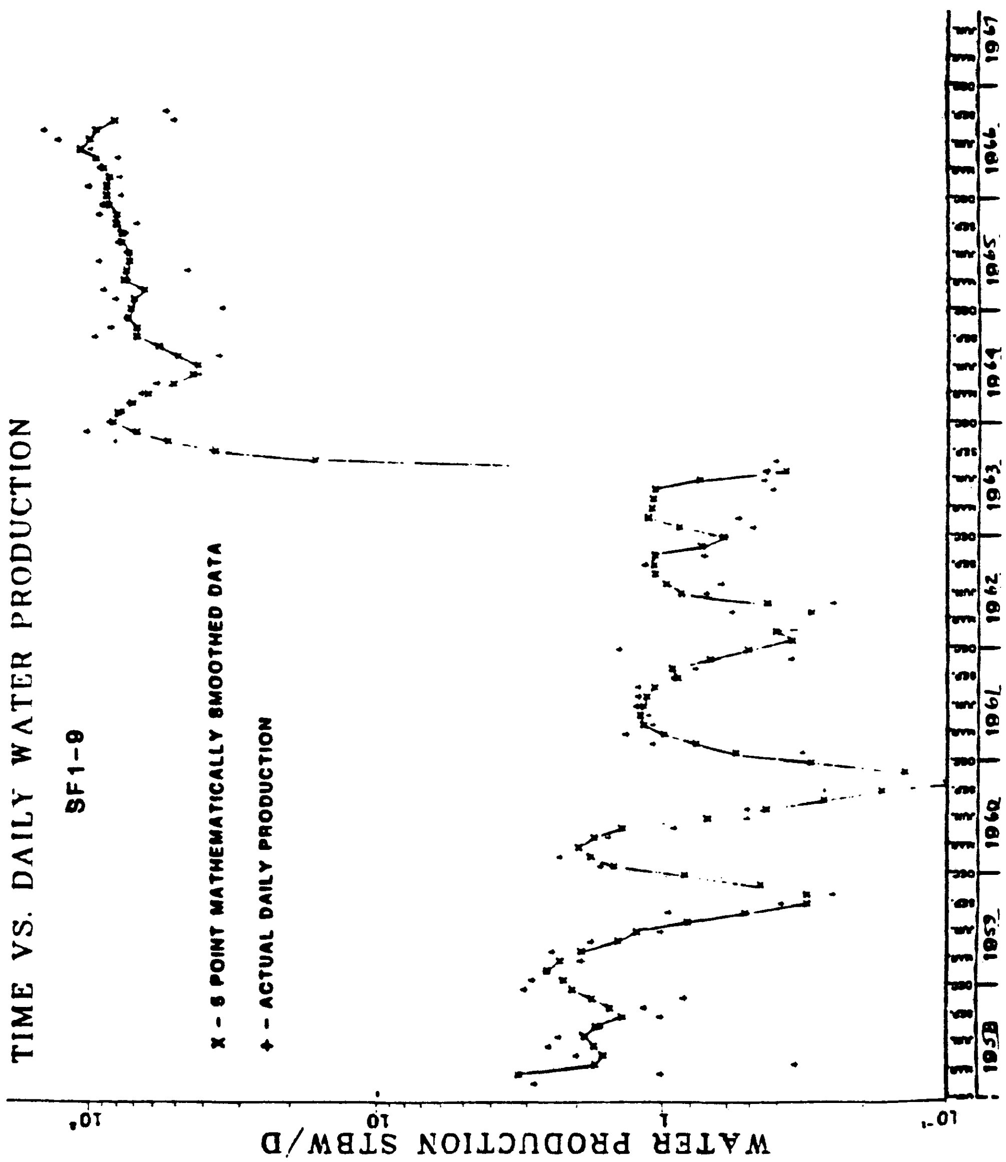
$$e_w = \frac{(767,855 - 403,899)\ 1.0218}{404,299} = 0.91985$$

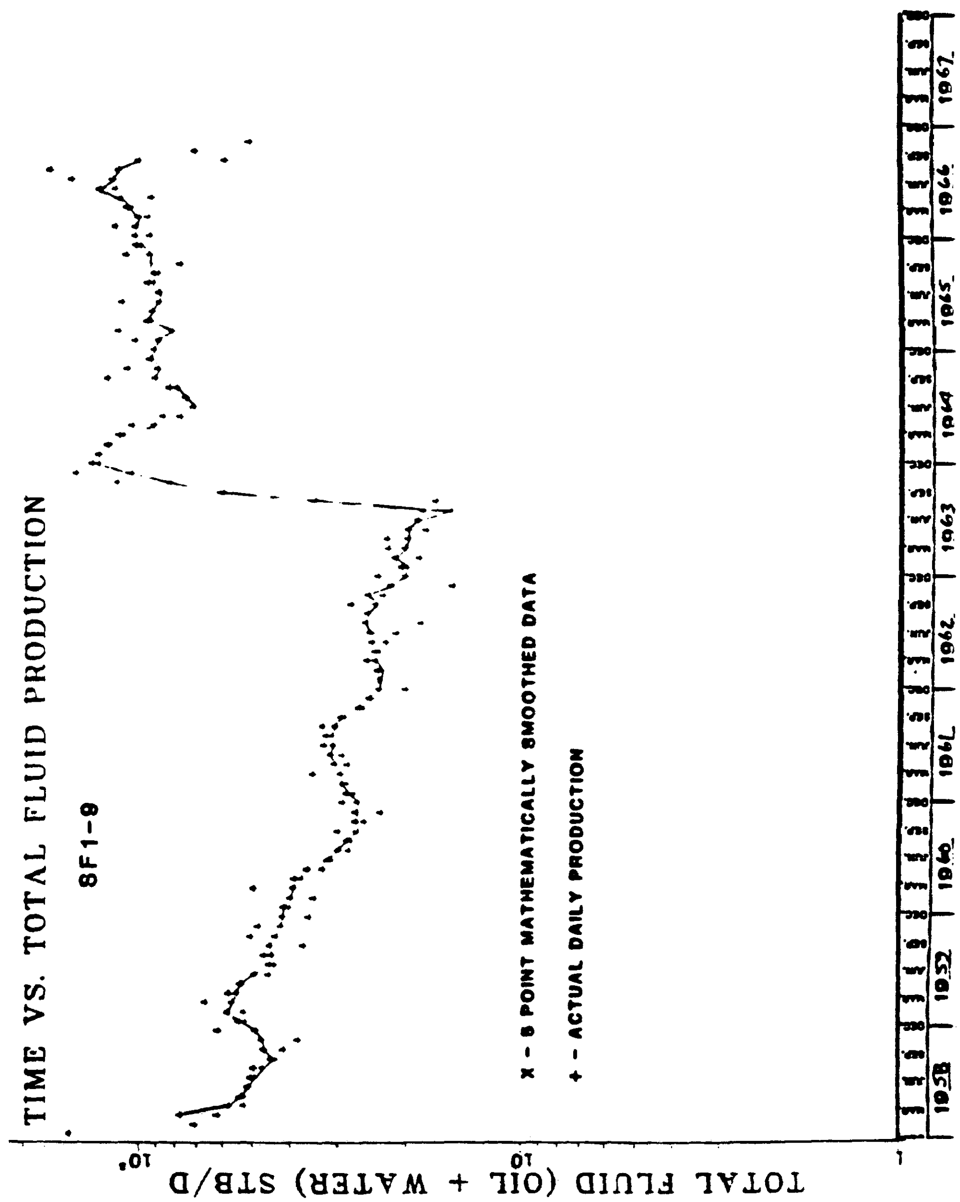
$$e_r = \frac{\frac{(4,288,000)}{(1 - .457)} [5*10^{-6}*.457 + 4*10^{-6}] (354)}{404,294} = 0.04988.$$

APPENDIX C

Production Decline Curves

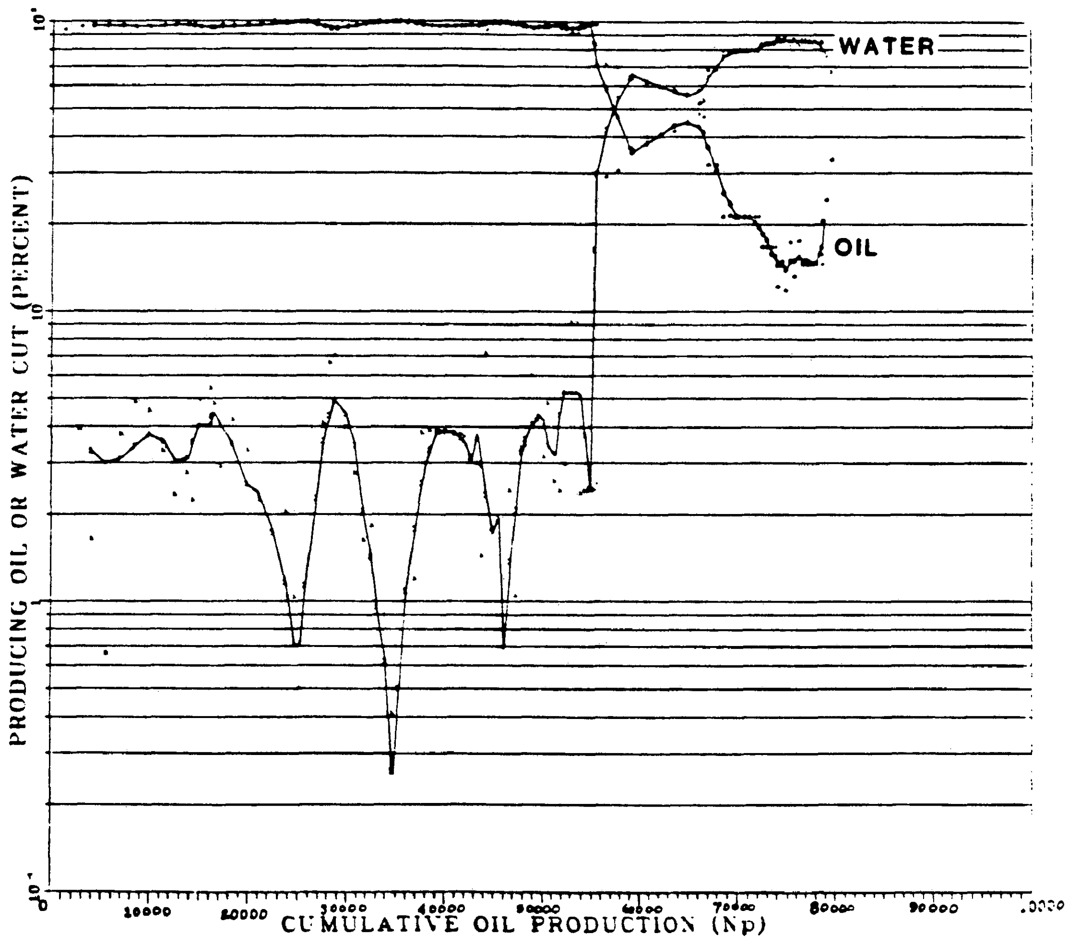

TIME VS. DAILY OIL PRODUCTION
SF1-9
+ - ACTUAL DAILY PRODUCTION
OIL PRODUCTION STBO/D

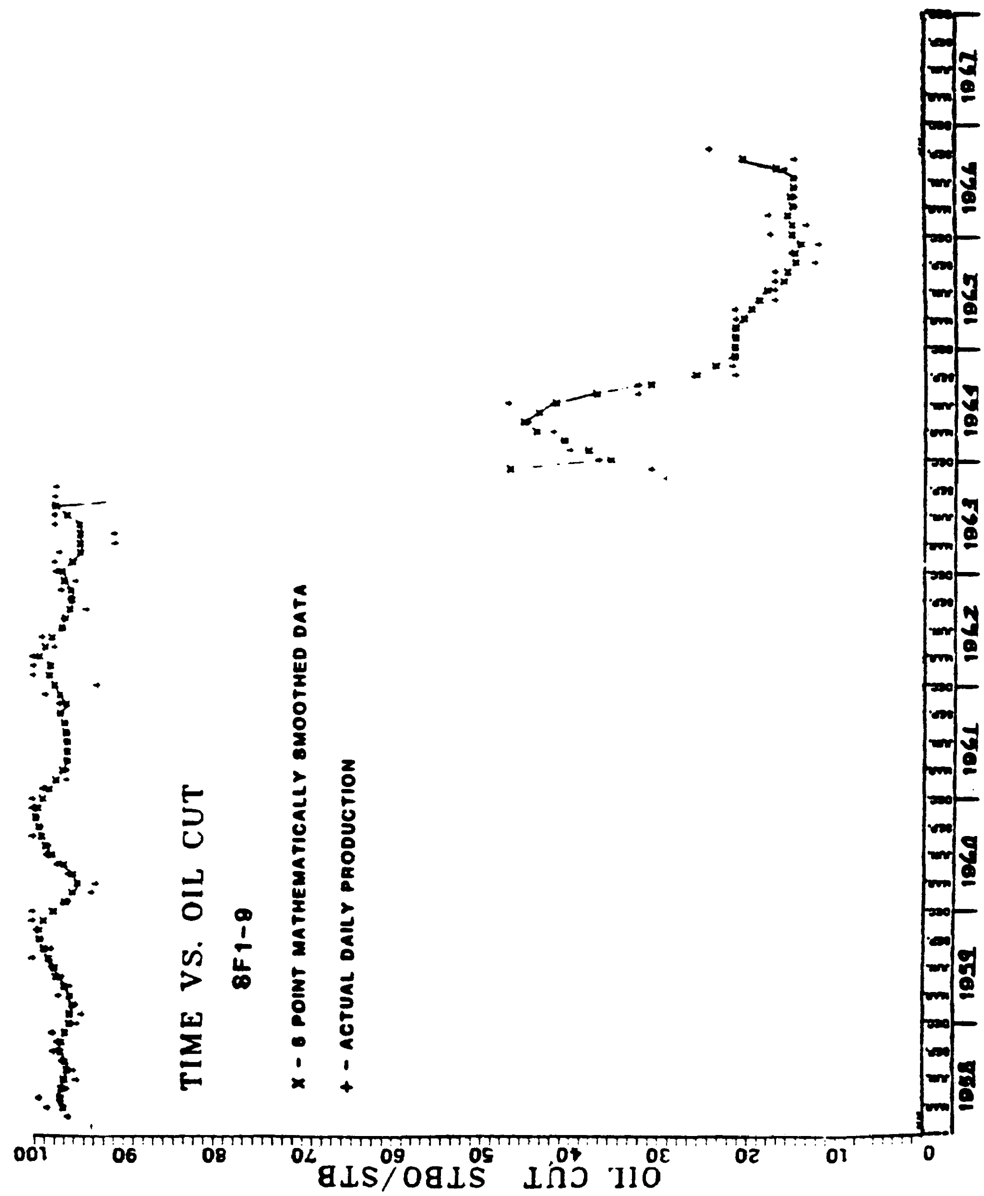

TIME VS. DAILY WATER PRODUCTION
SF1-9
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
WATER PRODUCTION STBW/D
1958
1959
1960
1961
1962
1963
1964
1965
1966
1967

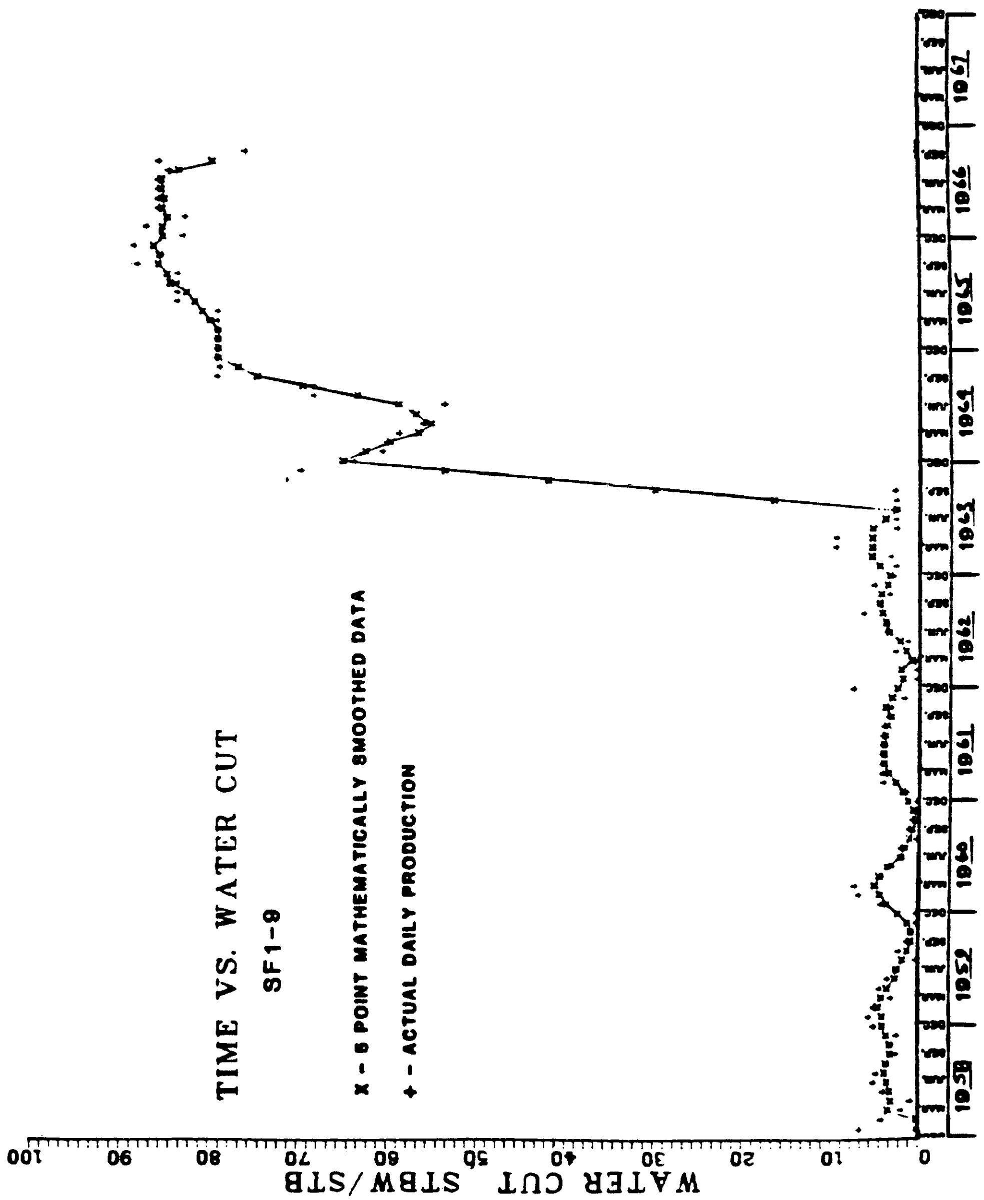


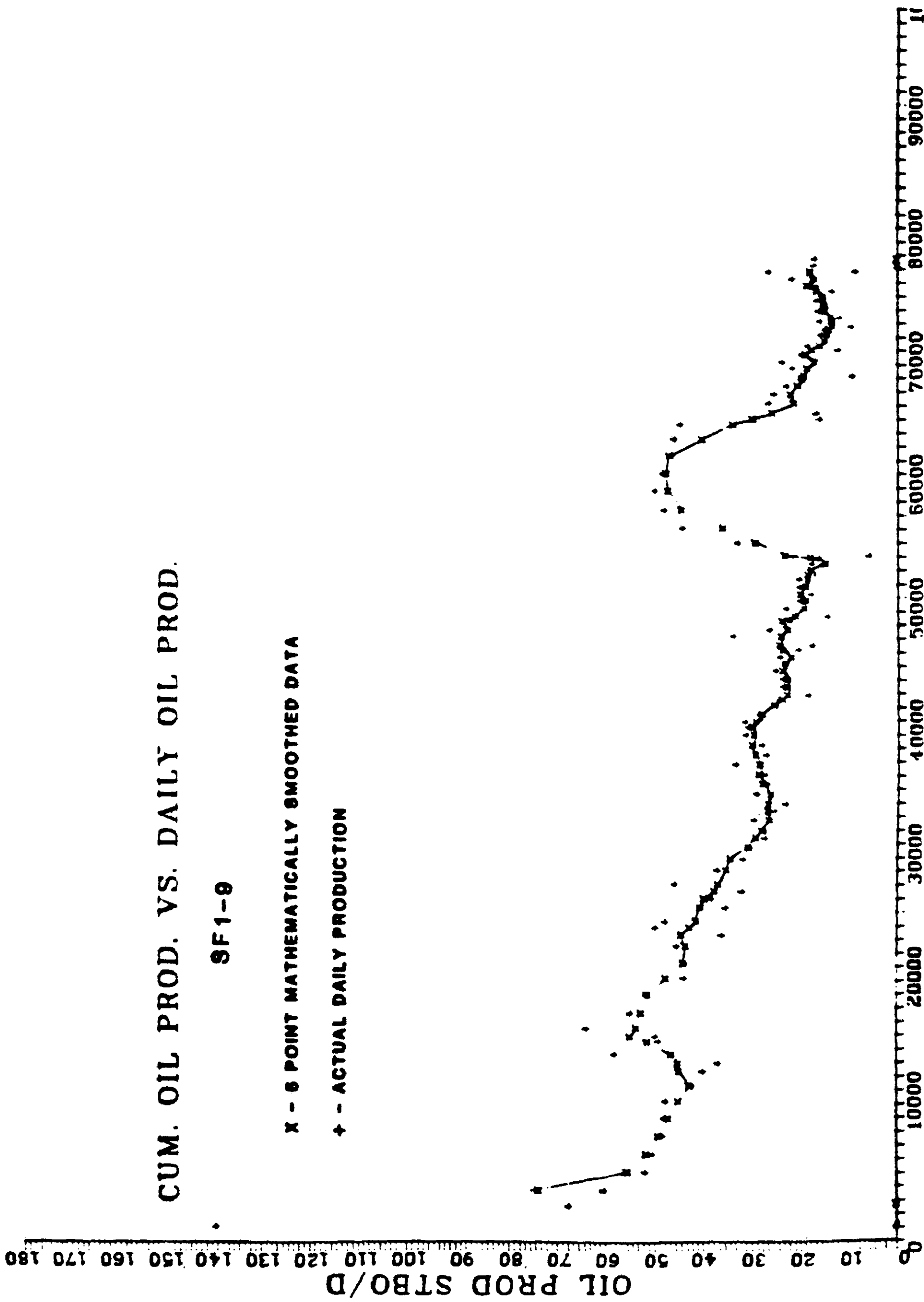
TIME VS. TOTAL FLUID PRODUCTION
SF1-9
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
TOTAL FLUID (OIL + WATER) STB/D
10²
10
1
1958
1959
1960
1961
1962
1963
1964
1965
1966
1967

OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION
SF1-9

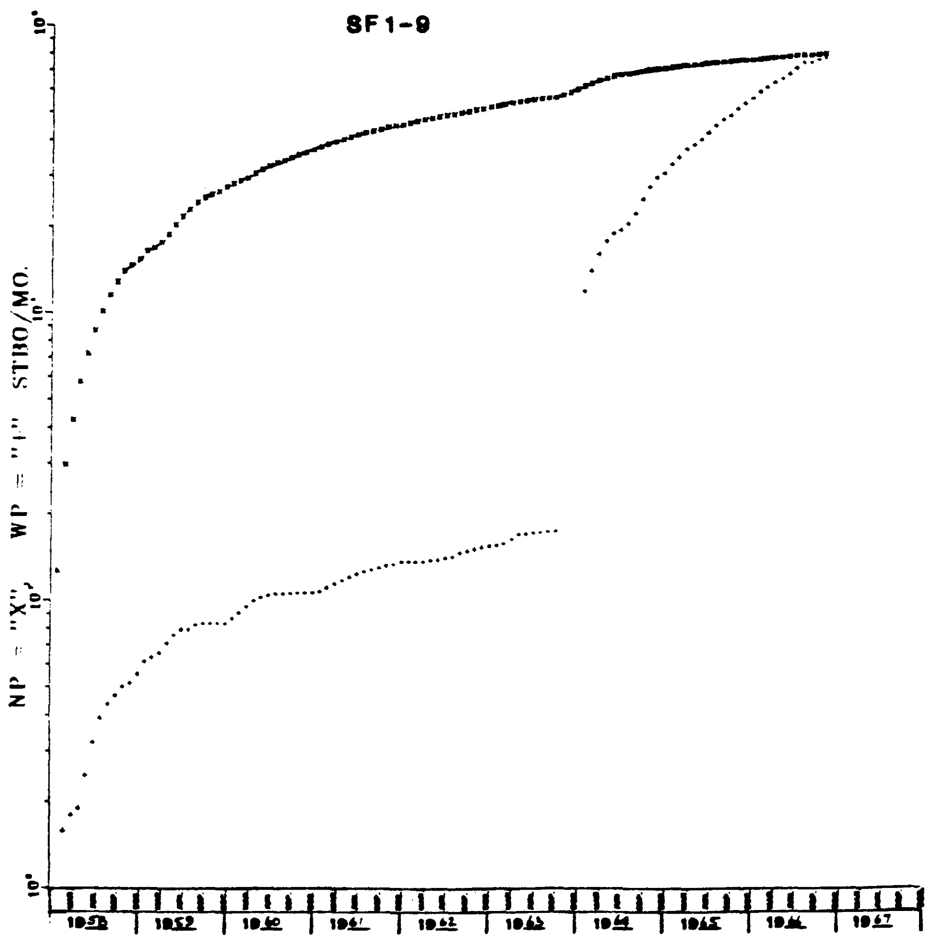


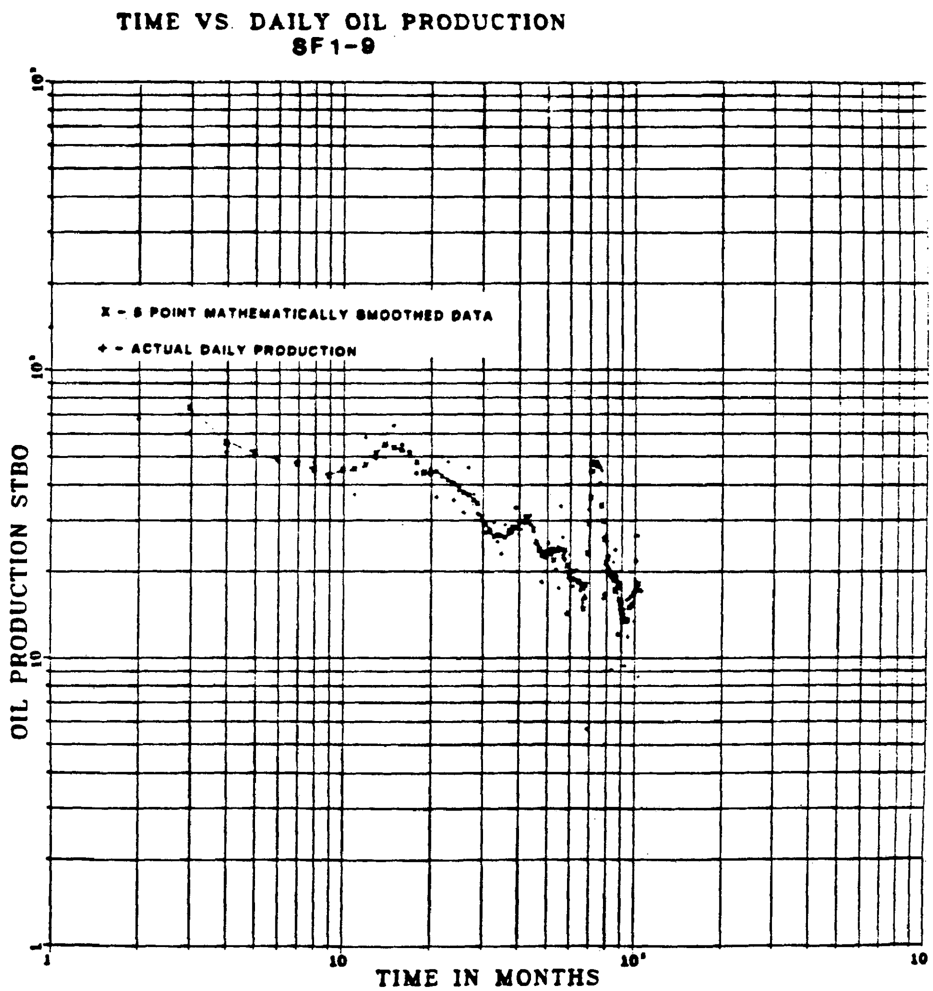

TIME VS. OIL CUT
SF1-9
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL CUT STBO/STB
0
10
20
30
40
50
60
70
80
90
100
1958
1959
1960
1961
1962
1963
1964
1965
1966
1967


TIME VS. WATER CUT
SF1-9
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
WATER CUT STBW/STB
0
10
20
30
40
50
60
70
80
90
100
1958
1959
1960
1961
1962
1963
1964
1965
1966
1967

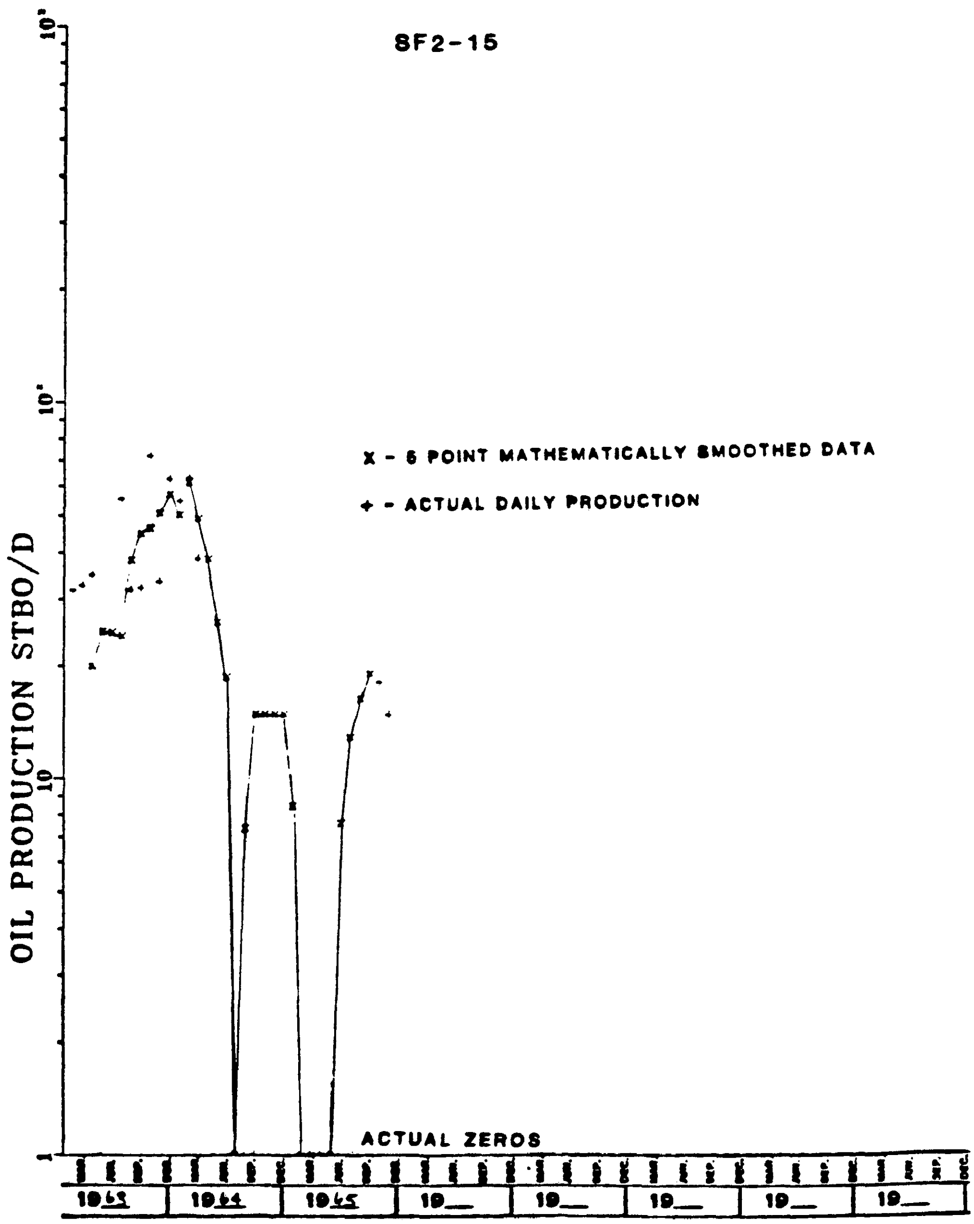

CUM. OIL PROD. VS. DAILY OIL PROD.
SF1-9
X - 6 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
CUMULATIVE OIL PRODUCTION (Np)
OIL PROD STBO/D

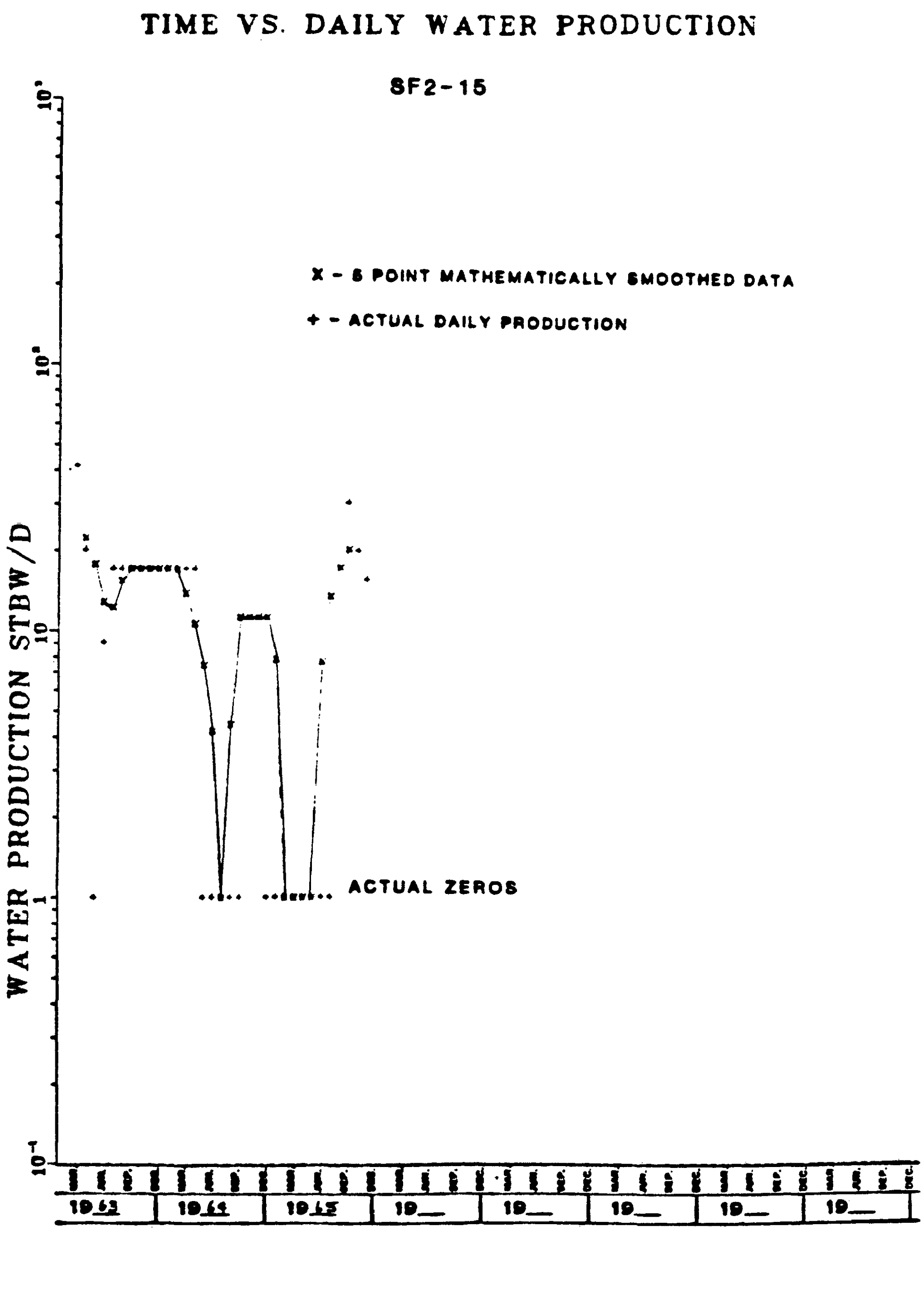
TIME VS. CUM. OIL AND WATER PRODN.



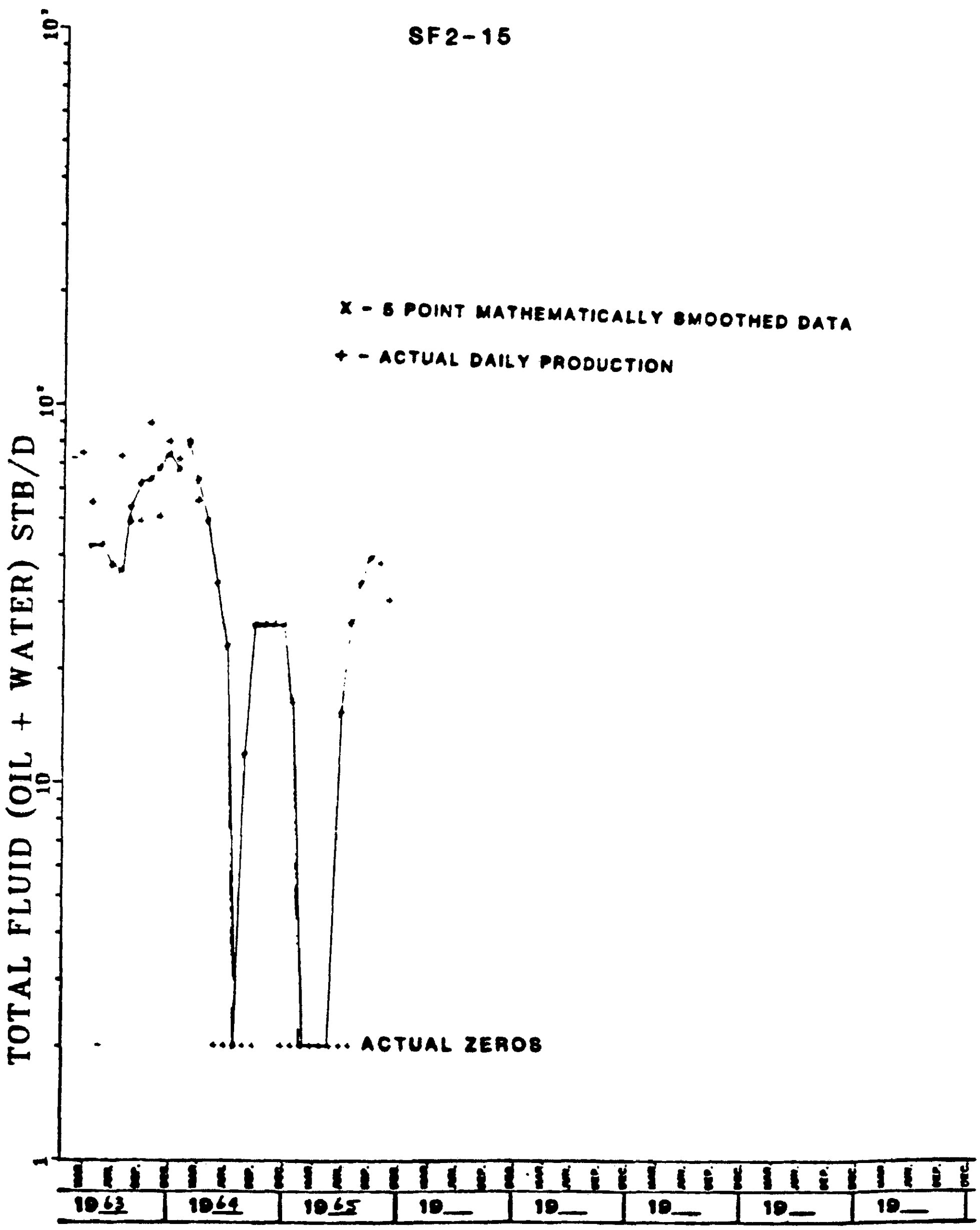

TIME VS. DAILY OIL PRODUCTION
SF1-9
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL PRODUCTION STBO
TIME IN MONTHS

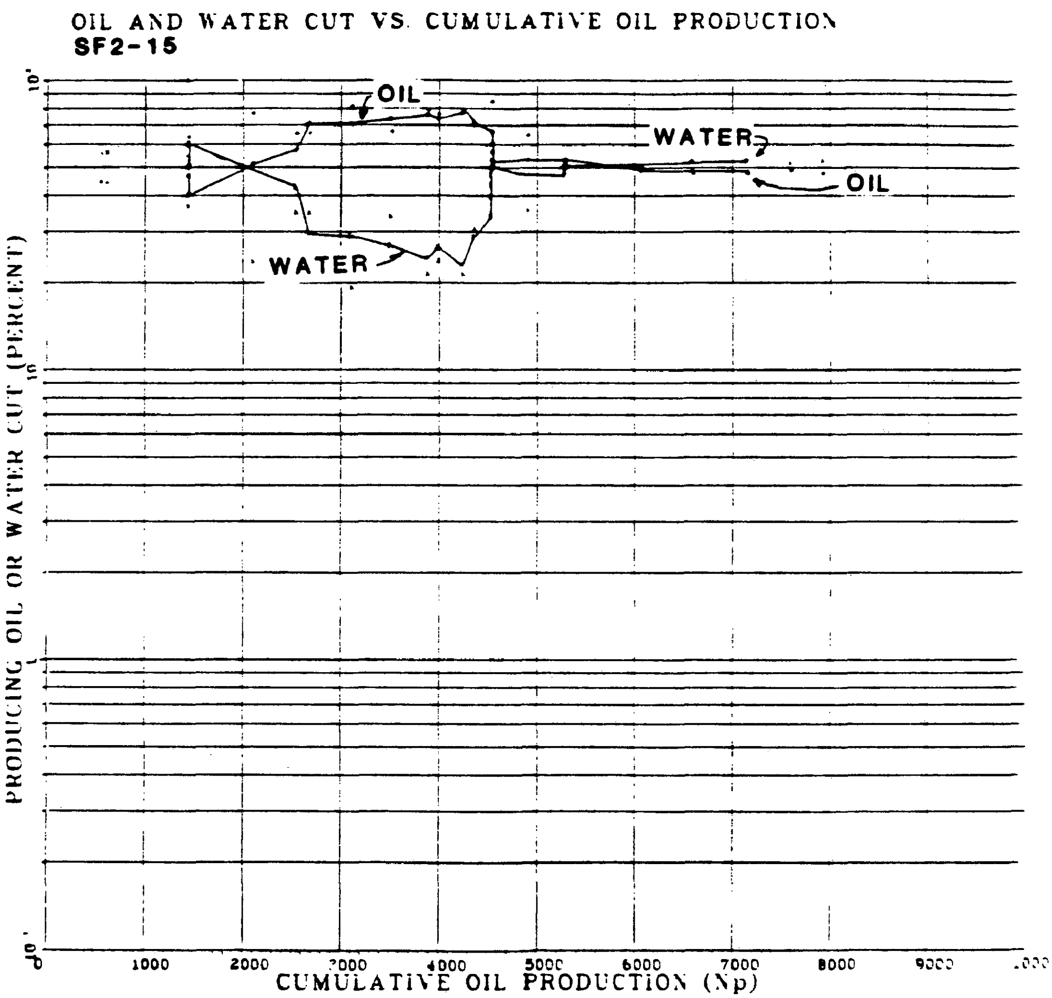
TIME VS. DAILY OIL PRODUCTION



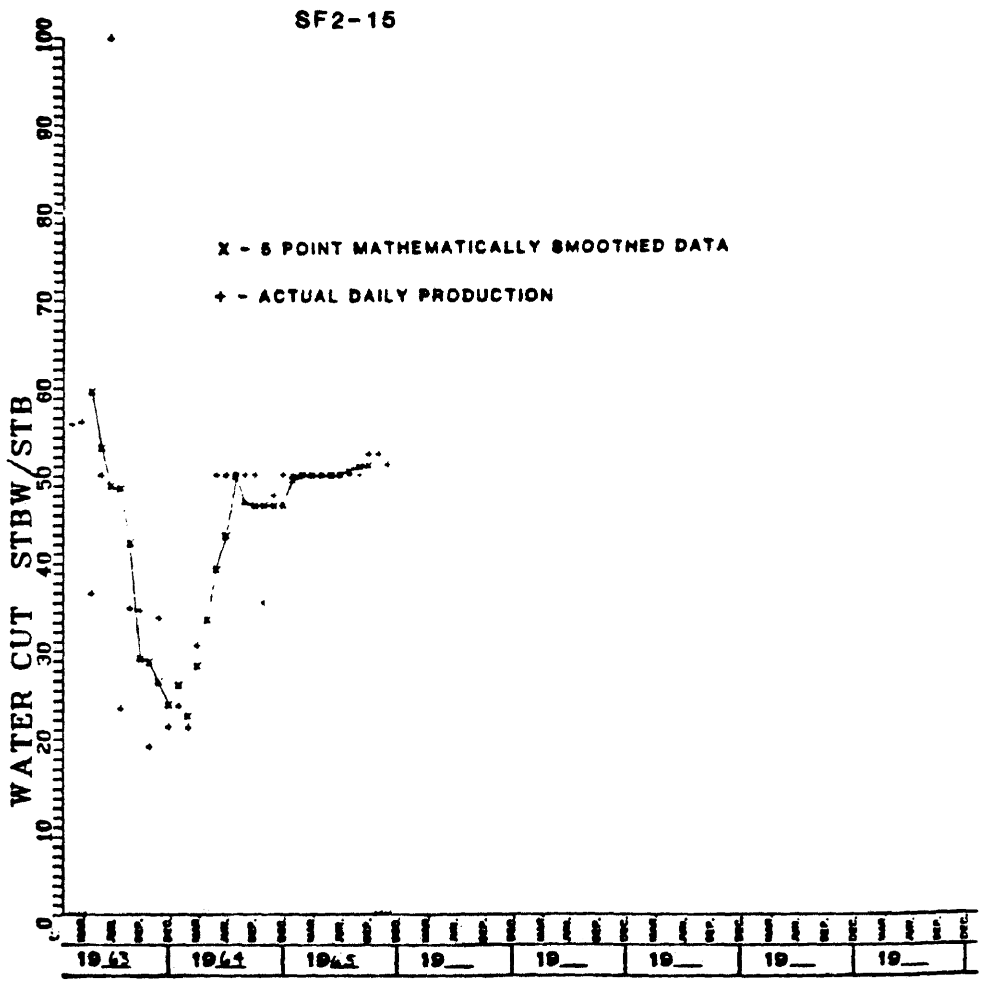

TIME VS. DAILY WATER PRODUCTION
SF2-15
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
ACTUAL ZEROS
WATER PRODUCTION STBW/D
19 63
19 64
19 65
19__
19__
19__
19__
19__

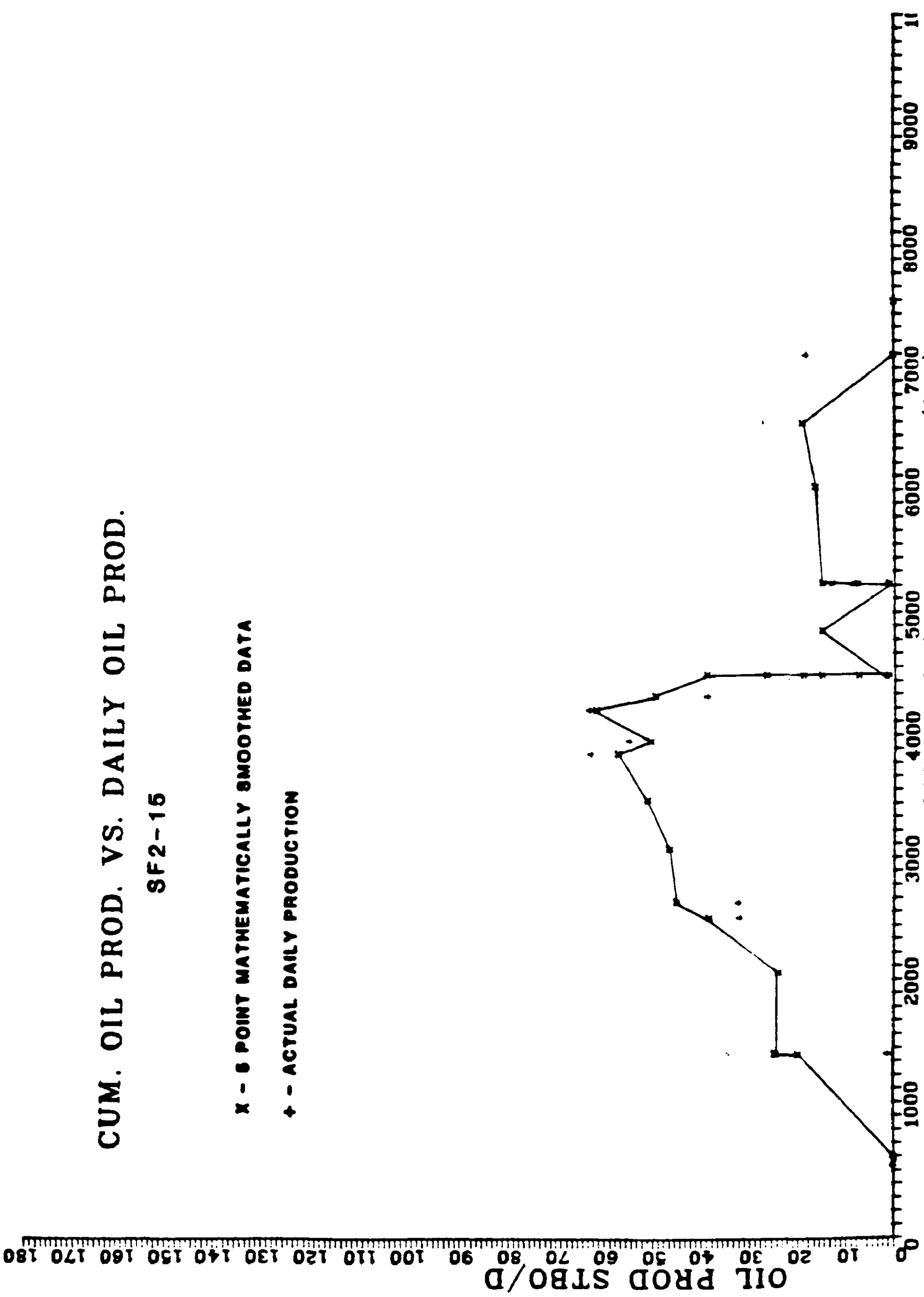
TIME VS. TOTAL FLUID PRODUCTION



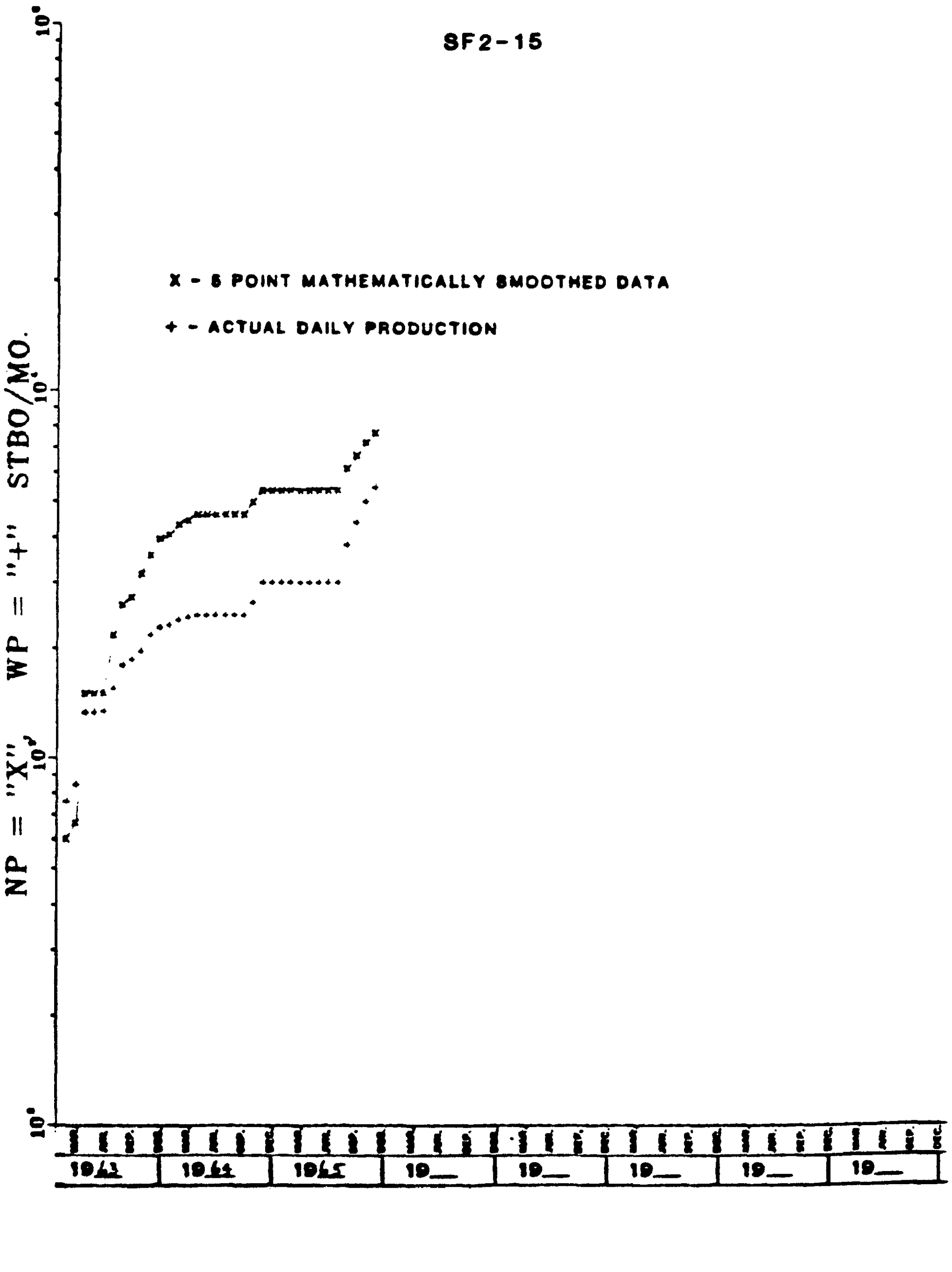

OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION
SF2-15
OIL
WATER
WATER
OIL
PRODUCING OIL OR WATER CUT (PERCENT)
CUMULATIVE OIL PRODUCTION (Np)
1000
2000
3000
4000
5000
6000
7000
8000
9000

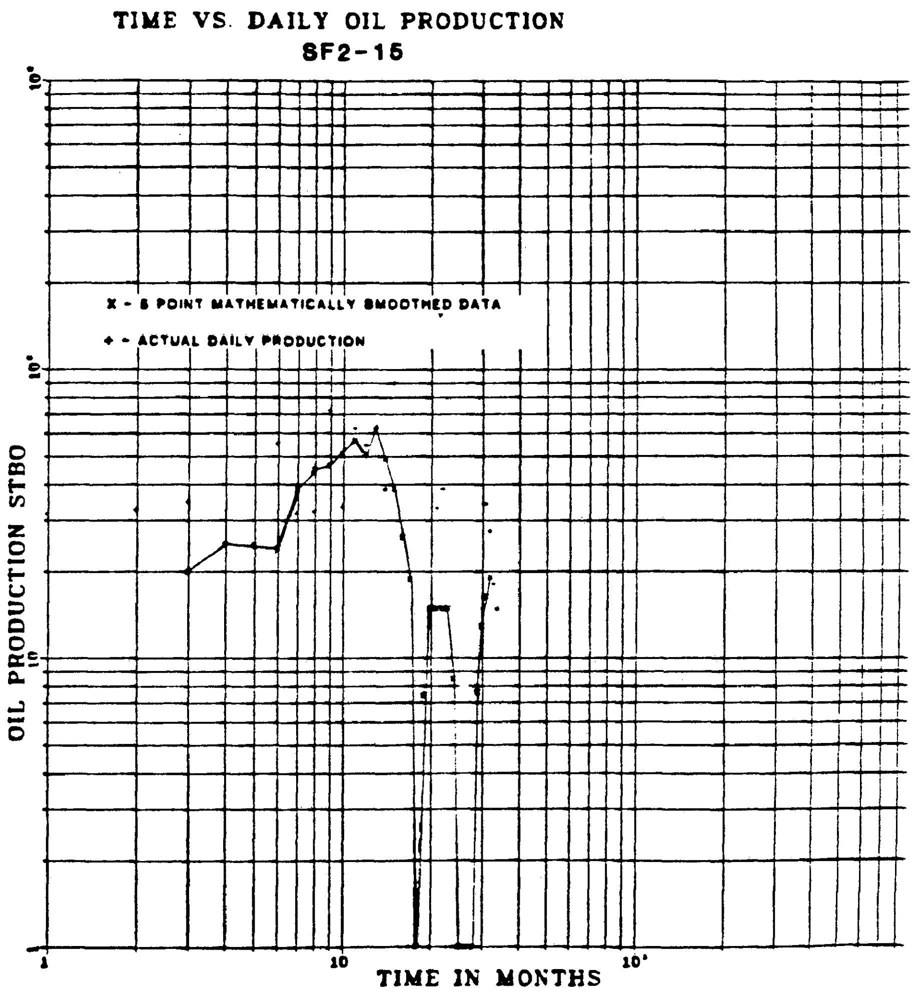
TIME VS. WATER CUT



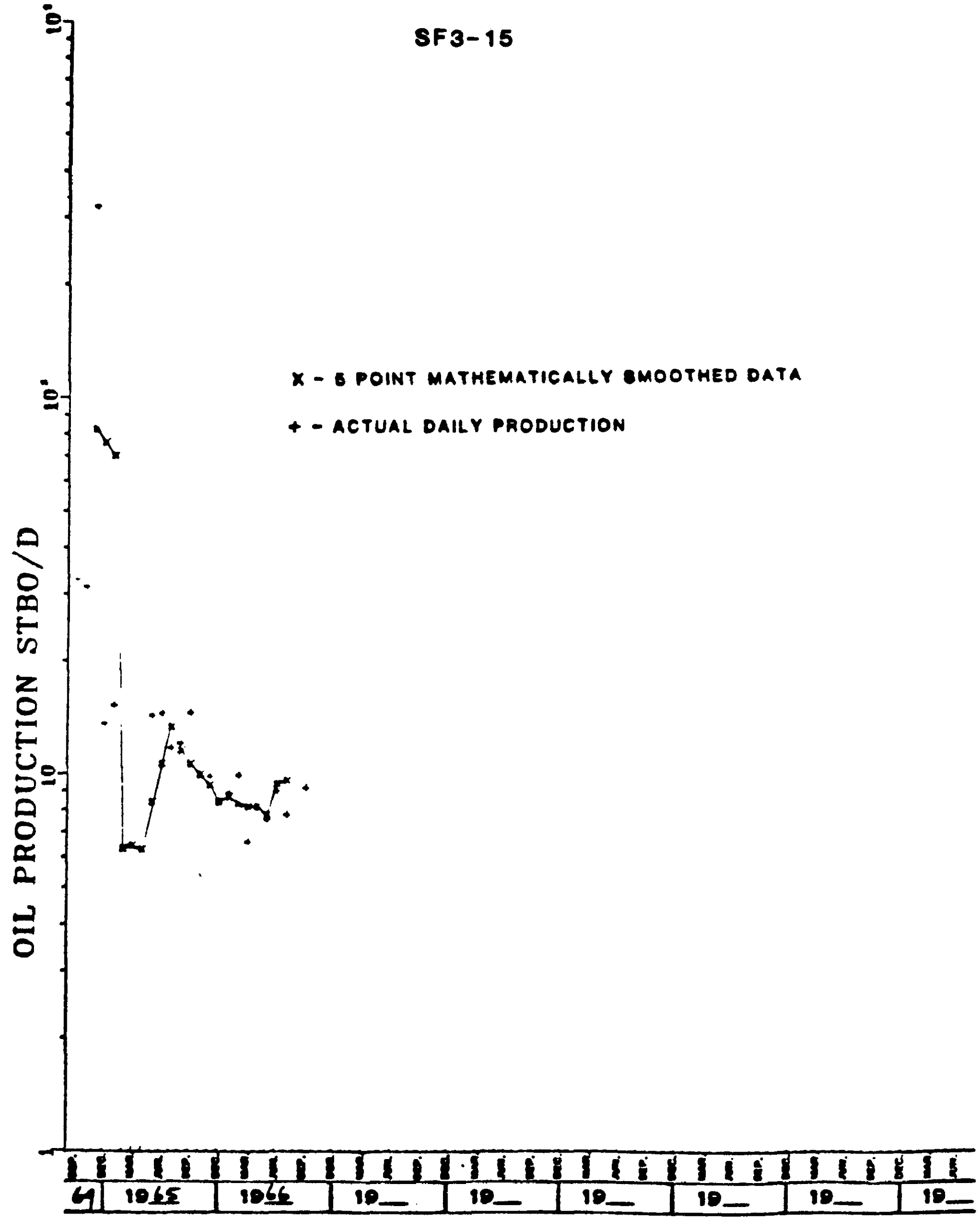

CUM. OIL PROD. VS. DAILY OIL PROD.
SF2-15
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
CUMULATIVE OIL PRODUCTION (Np)
OIL PROD STBO/D

TIME VS. CUM. OIL AND WATER PRODN.

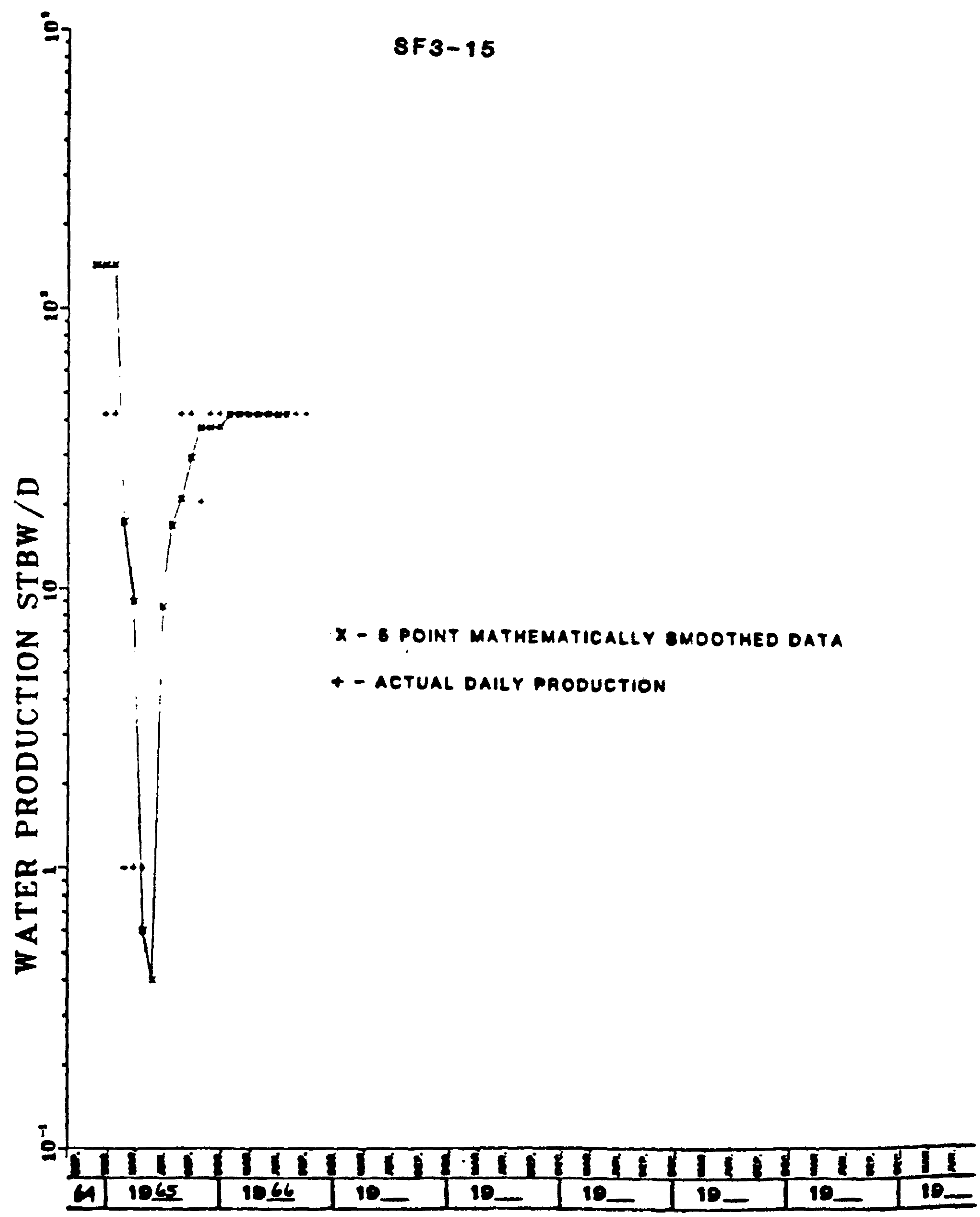



TIME VS. DAILY OIL PRODUCTION
SF2-15
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL PRODUCTION STBO
TIME IN MONTHS
1
10

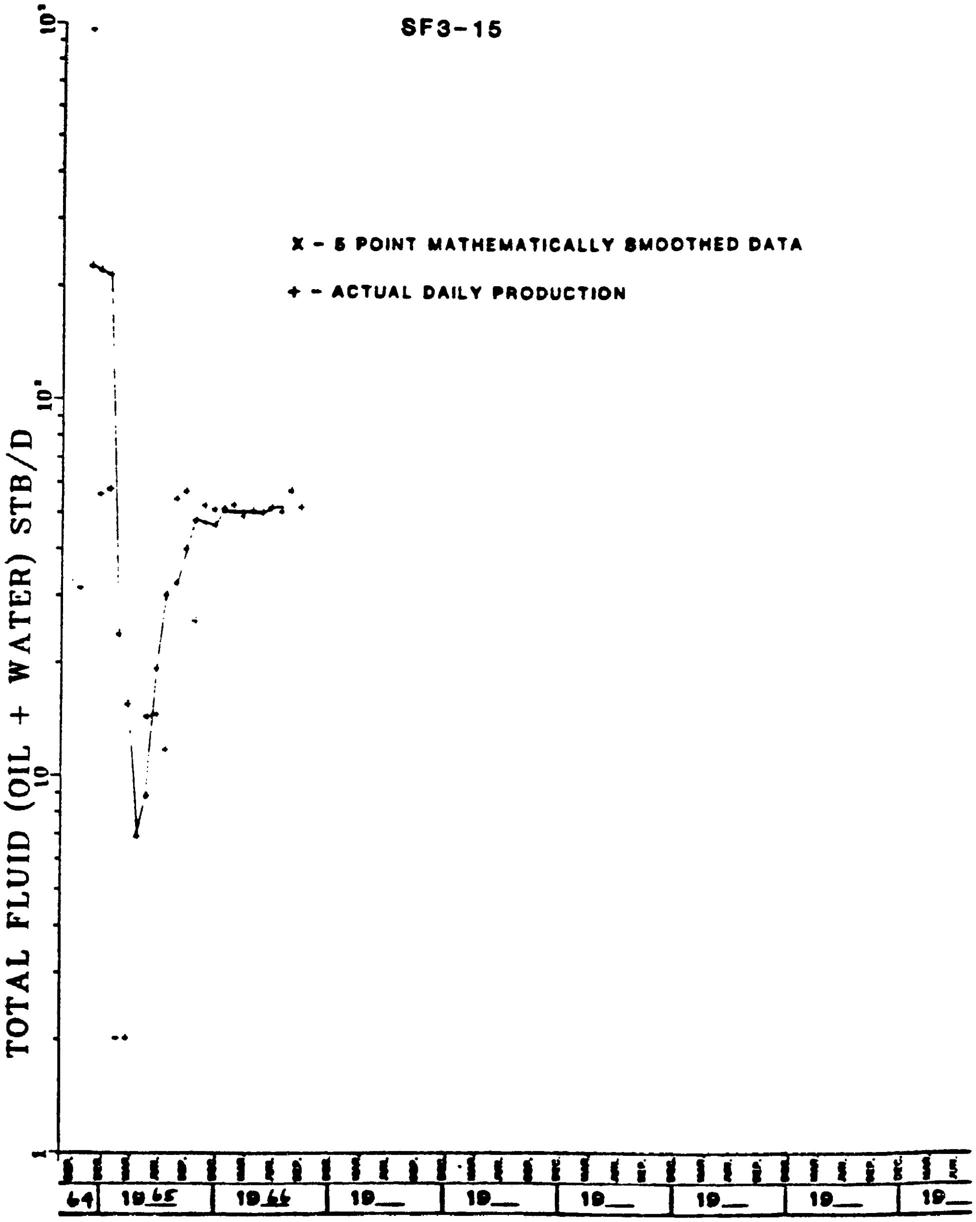
TIME VS. DAILY OIL PRODUCTION



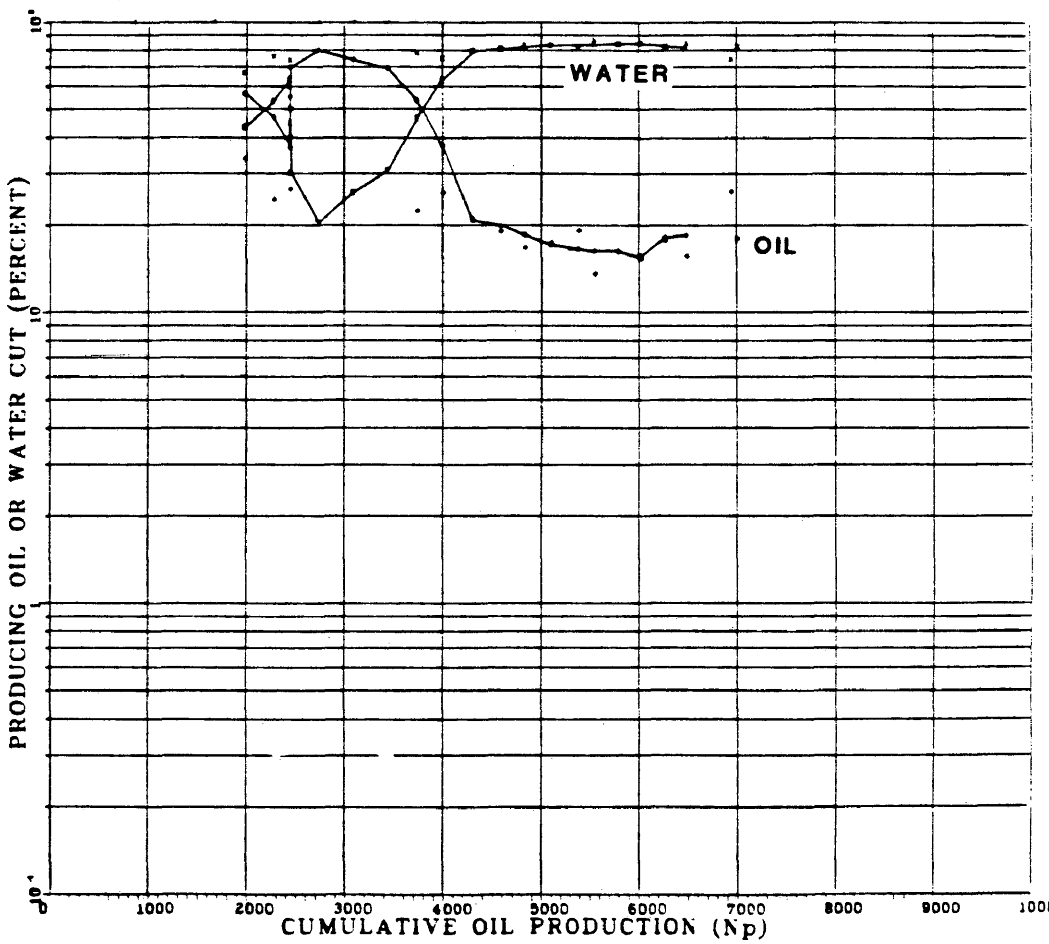
TIME VS. DAILY WATER PRODUCTION

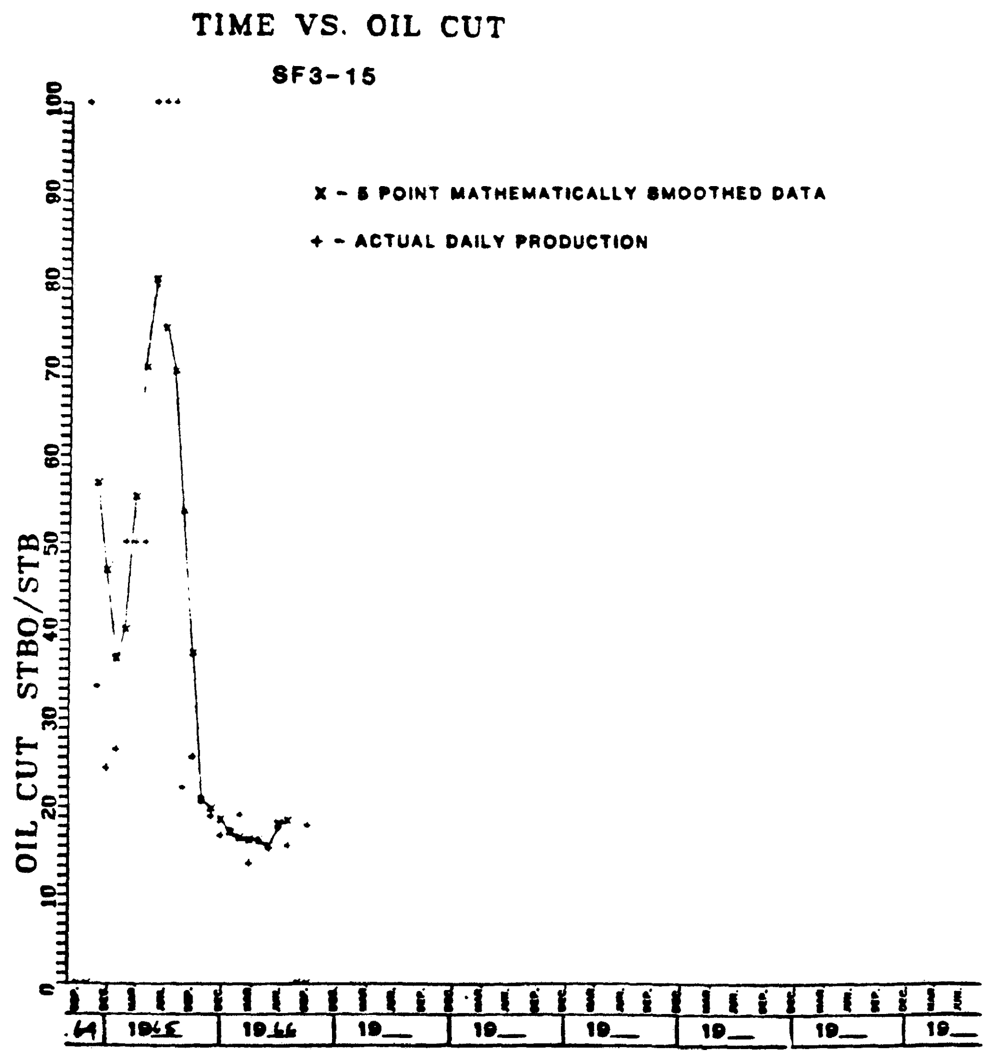


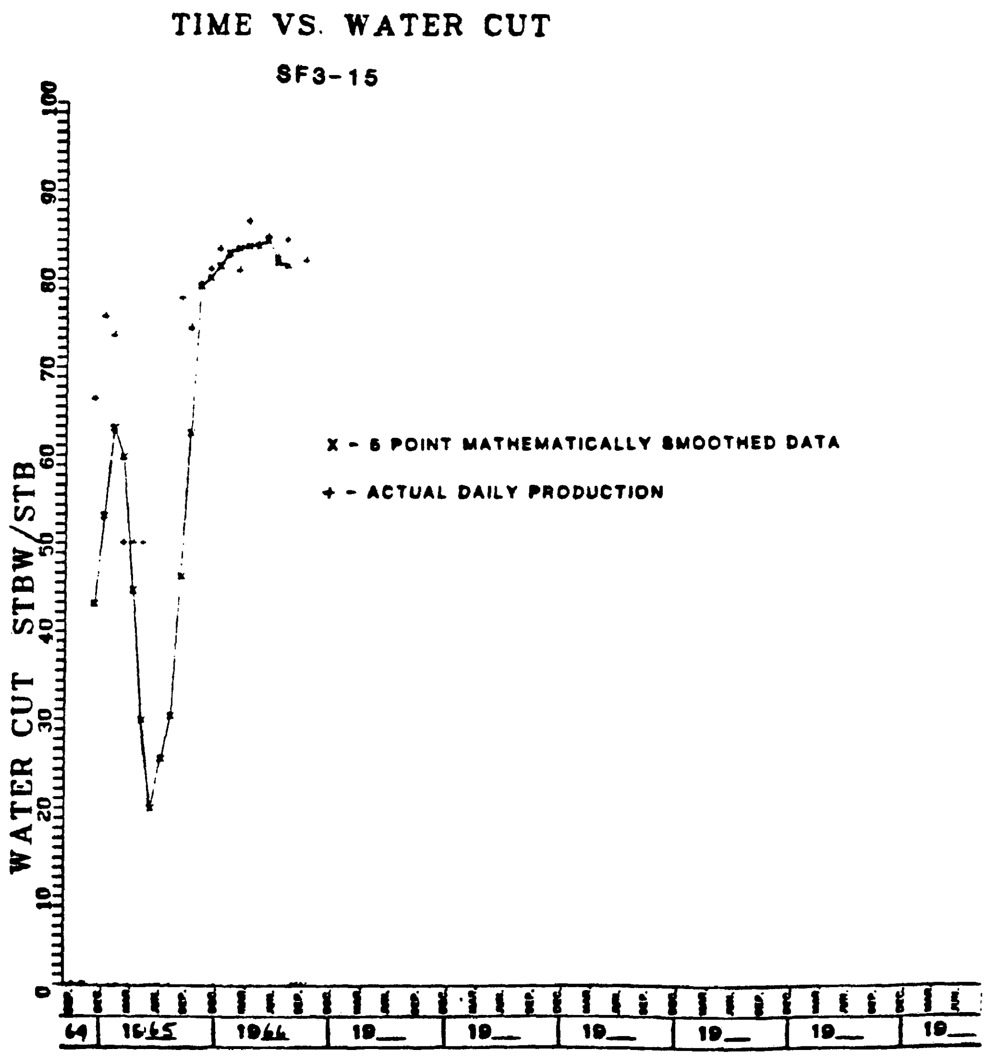
TIME VS. TOTAL FLUID PRODUCTION



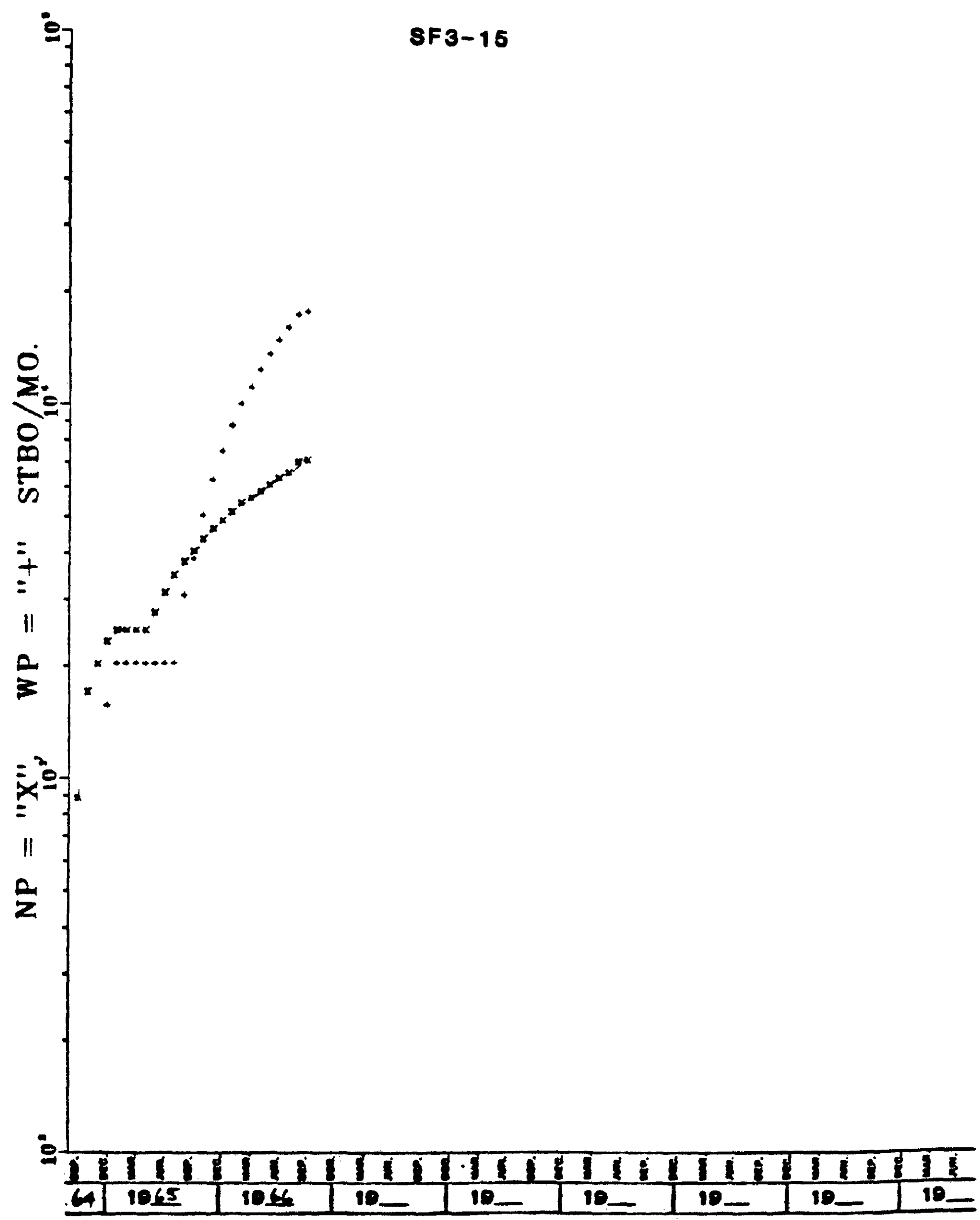
OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION
SF3-15

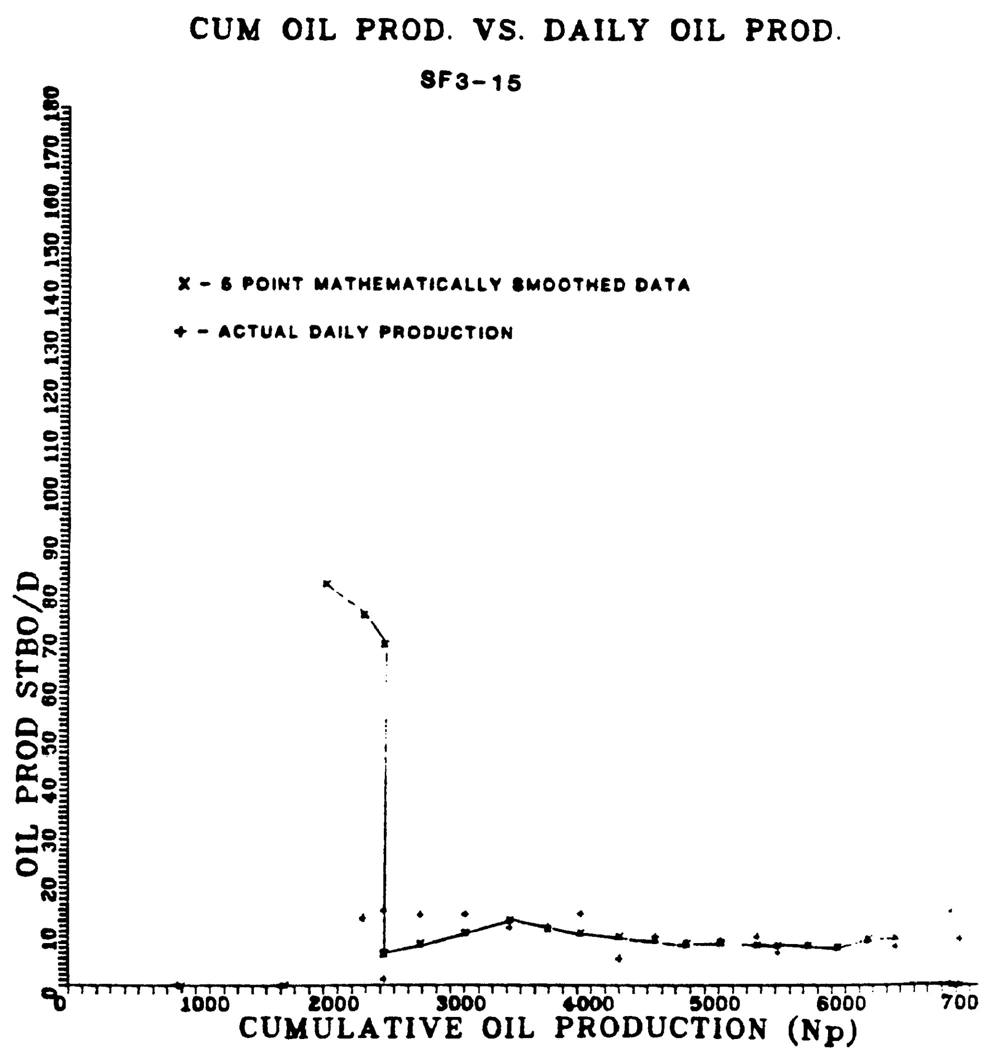


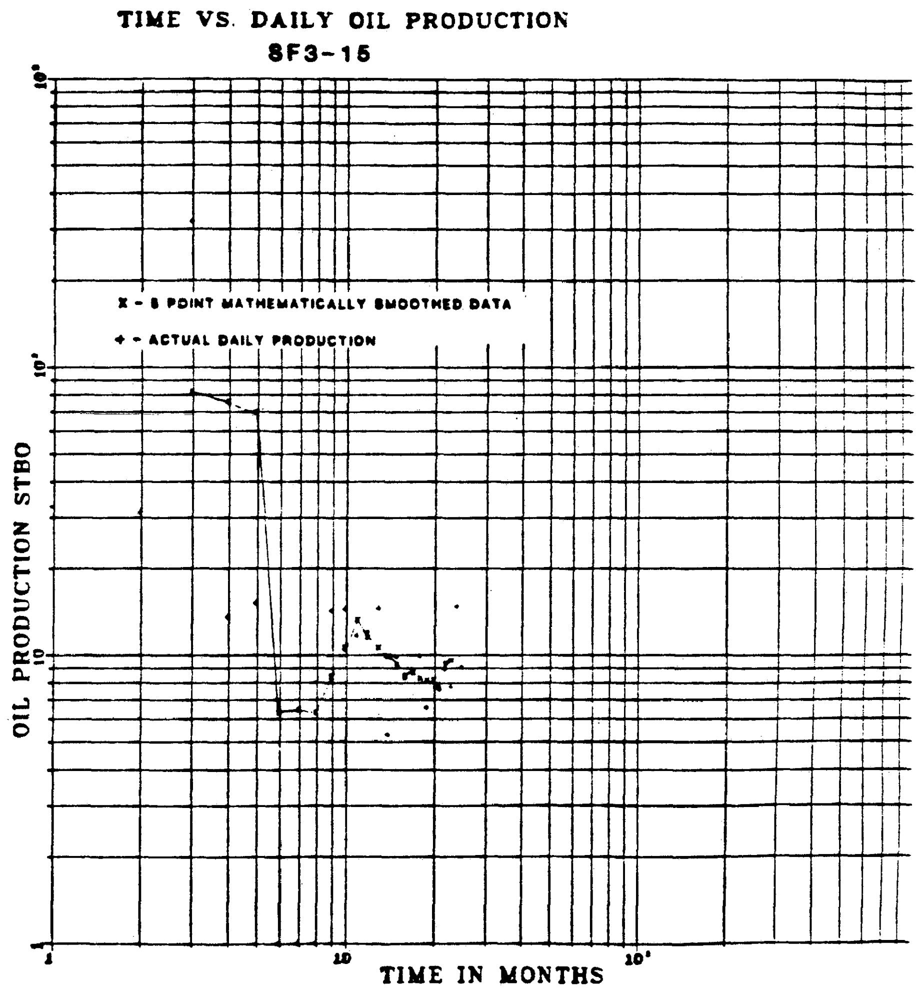

TIME VS. OIL CUT
SF3-15
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL CUT STBO/STB
0
10
20
30
40
50
60
70
80
90
100
.64
1965
1966
19__
19__
19__
19__
19__
19__


TIME VS. WATER CUT
SF3-15
WATER CUT STBW/STB
0
10
20
30
40
50
60
70
80
90
100
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
64
1965
1966
19__
19__
19__
19__
19__
19__

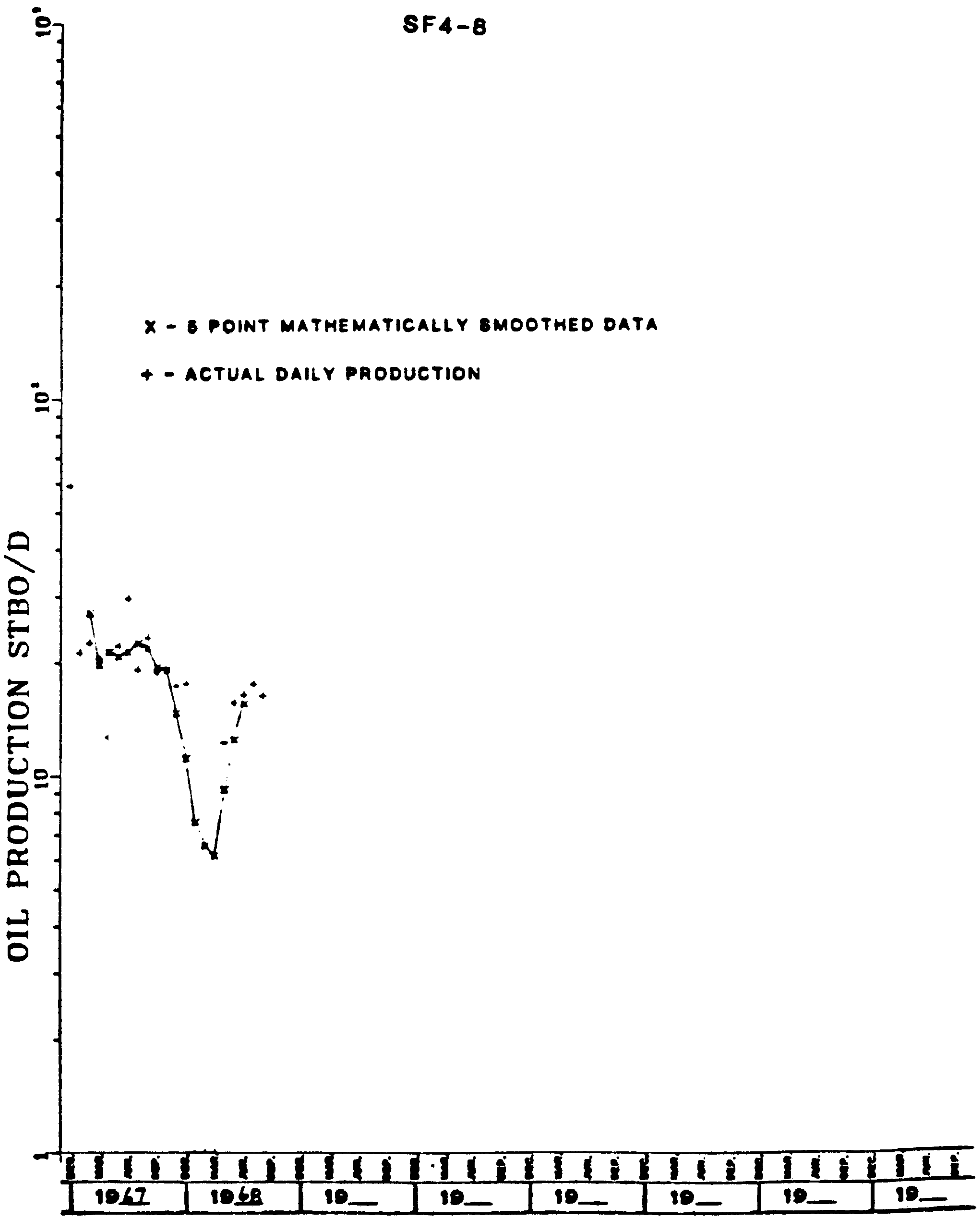
TIME VS. CUM. OIL AND WATER PRODN



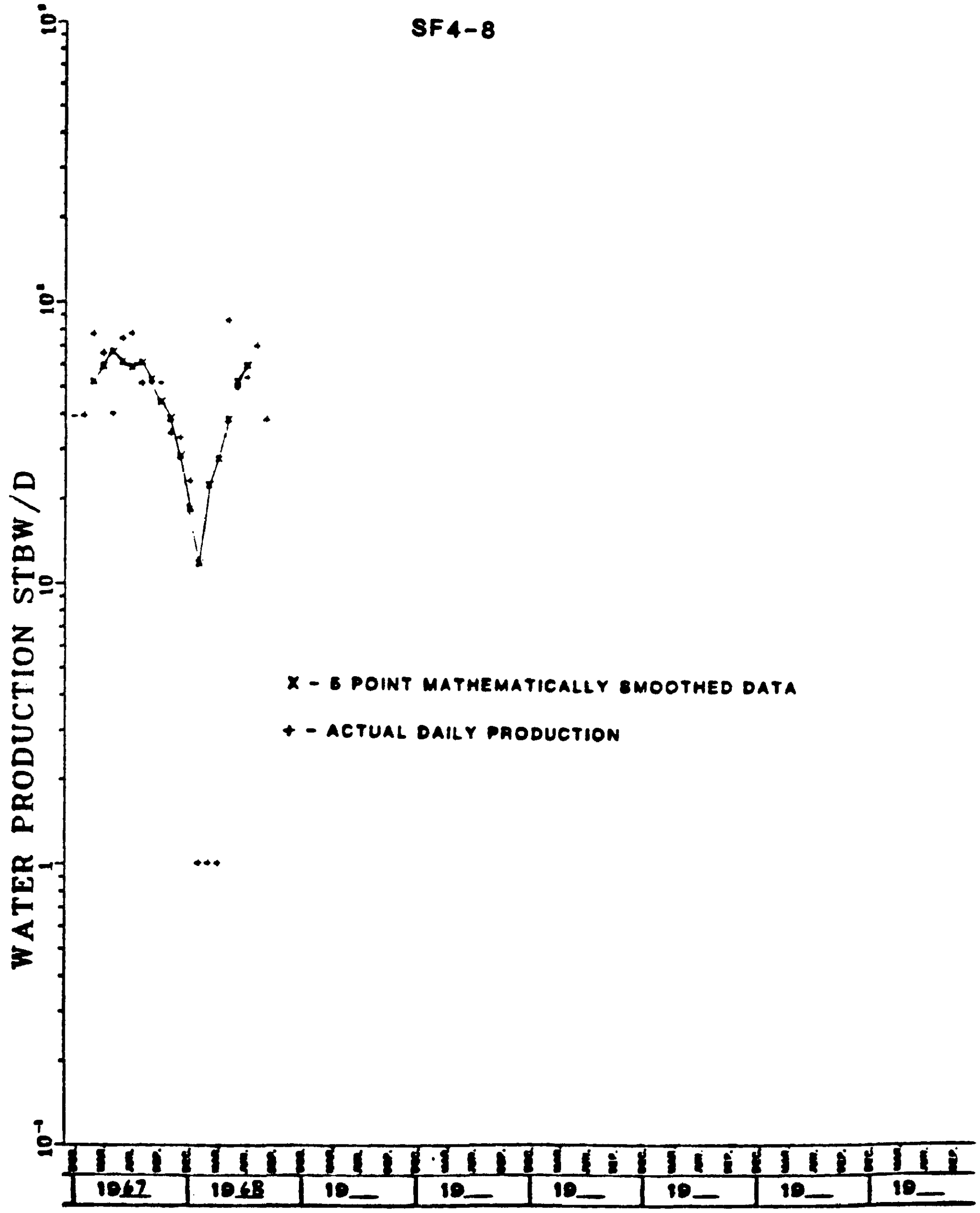

CUM OIL PROD. VS. DAILY OIL PROD.
SF3-15
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL PROD STBO/D
0 10 20 30 40 50 60 70 80 90 100 110 120 130 140 150 160 170 180
0 1000 2000 3000 4000 5000 6000 700
CUMULATIVE OIL PRODUCTION (Np)


TIME VS. DAILY OIL PRODUCTION
SF3-15
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL PRODUCTION STBO
TIME IN MONTHS
1
10
10²
1
10
10²
10³

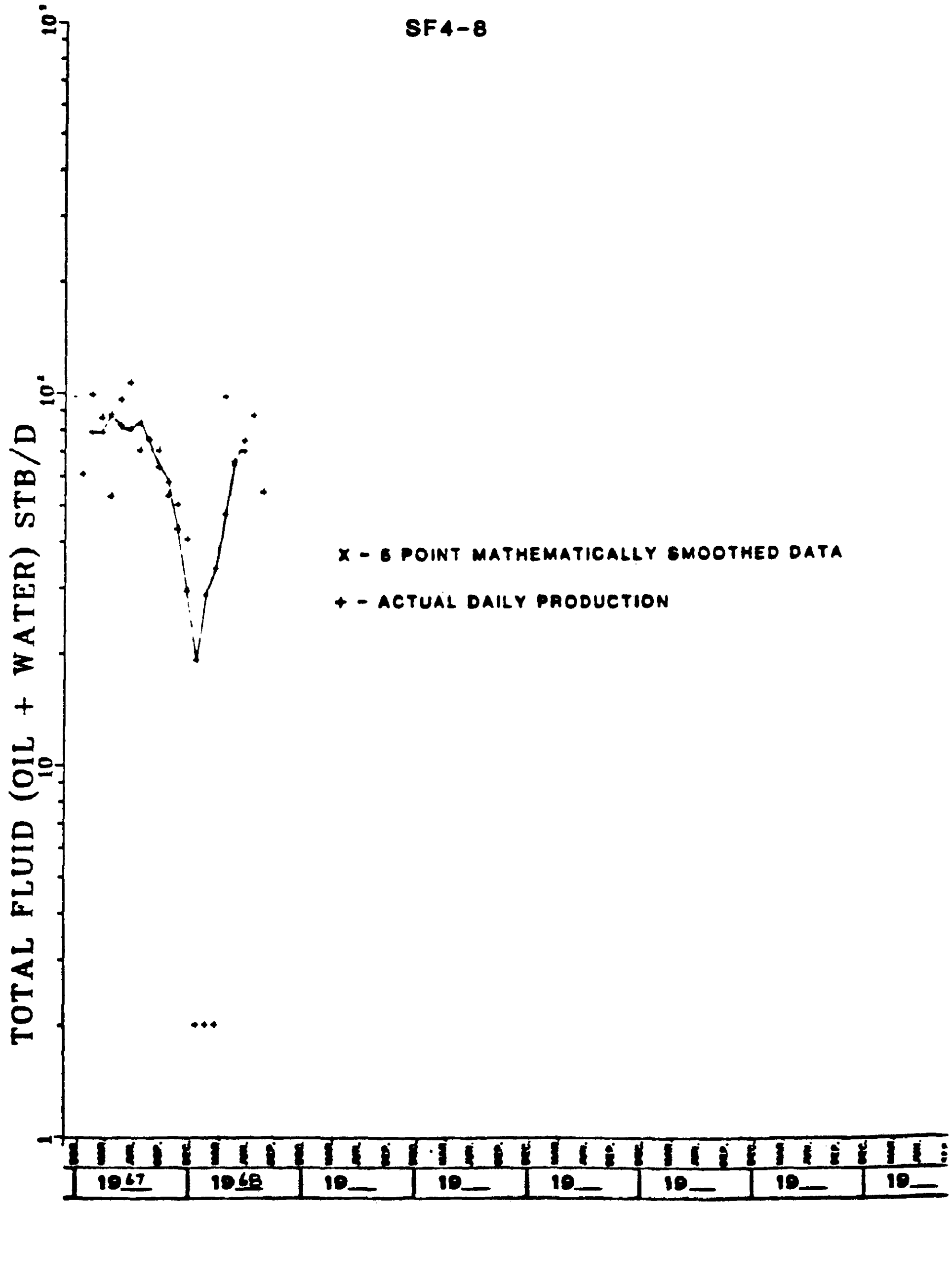
TIME VS. DAILY OIL PRODUCTION



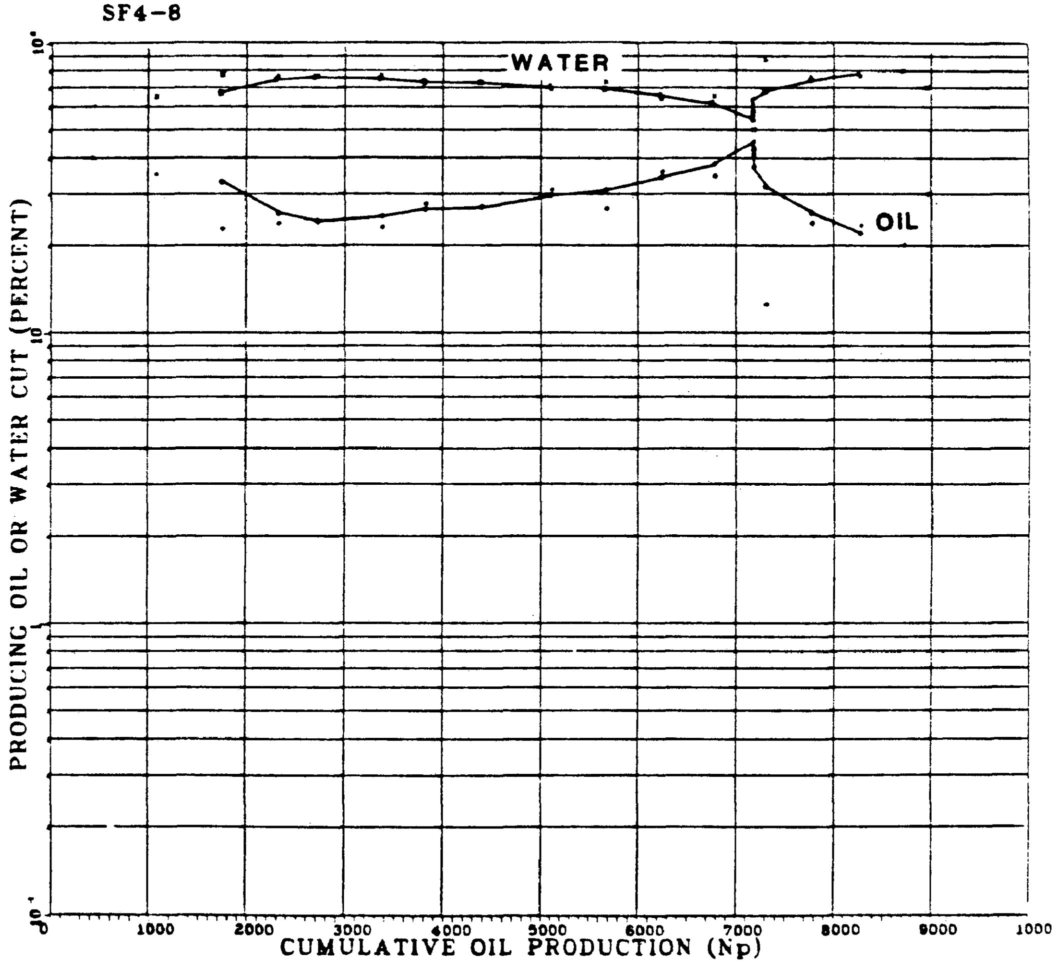
TIME VS. DAILY WATER PRODUCTION

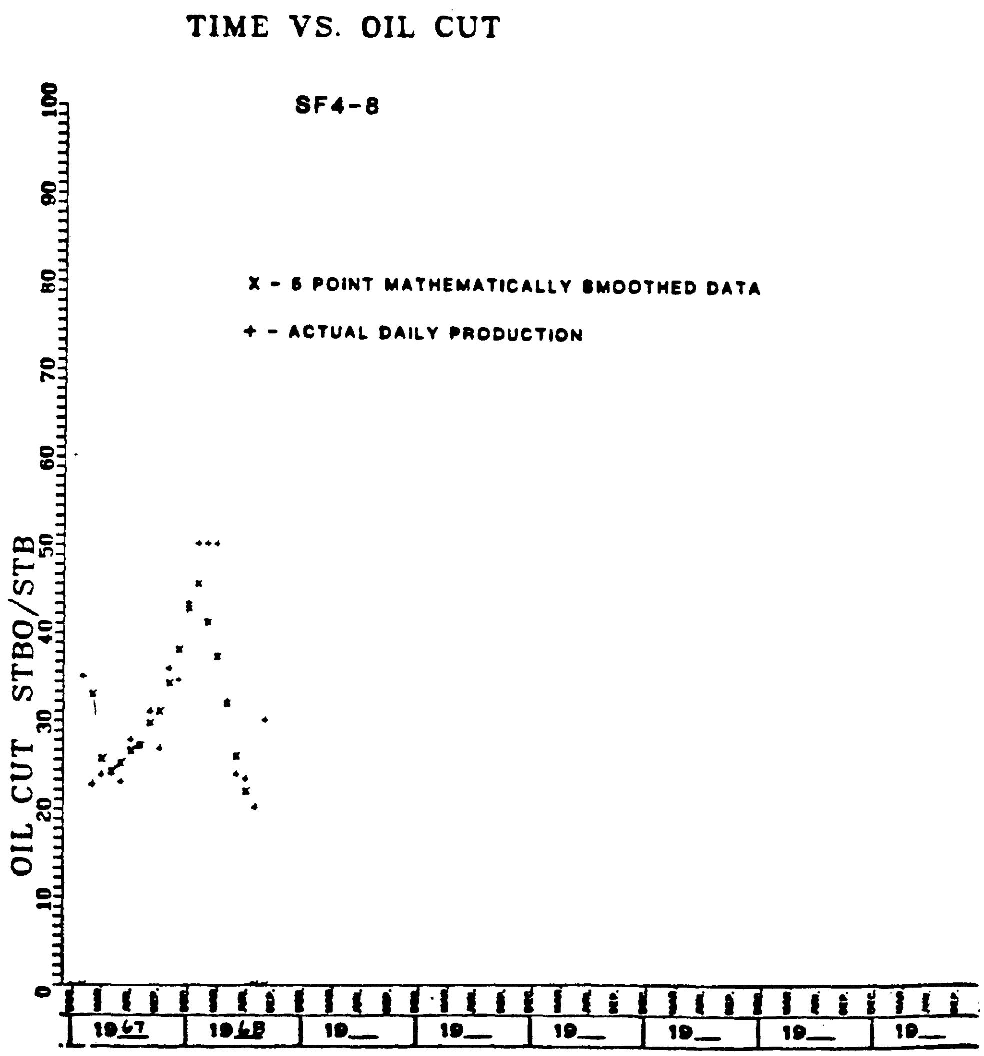


TIME VS. TOTAL FLUID PRODUCTION

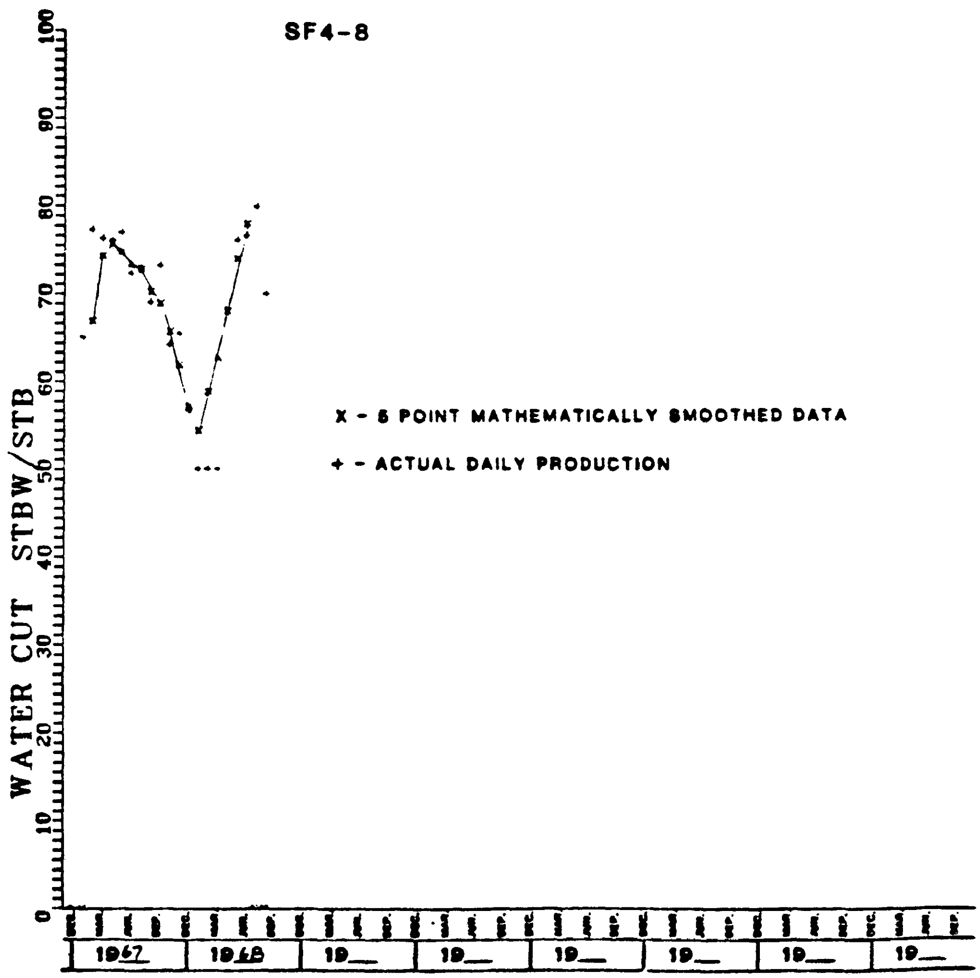


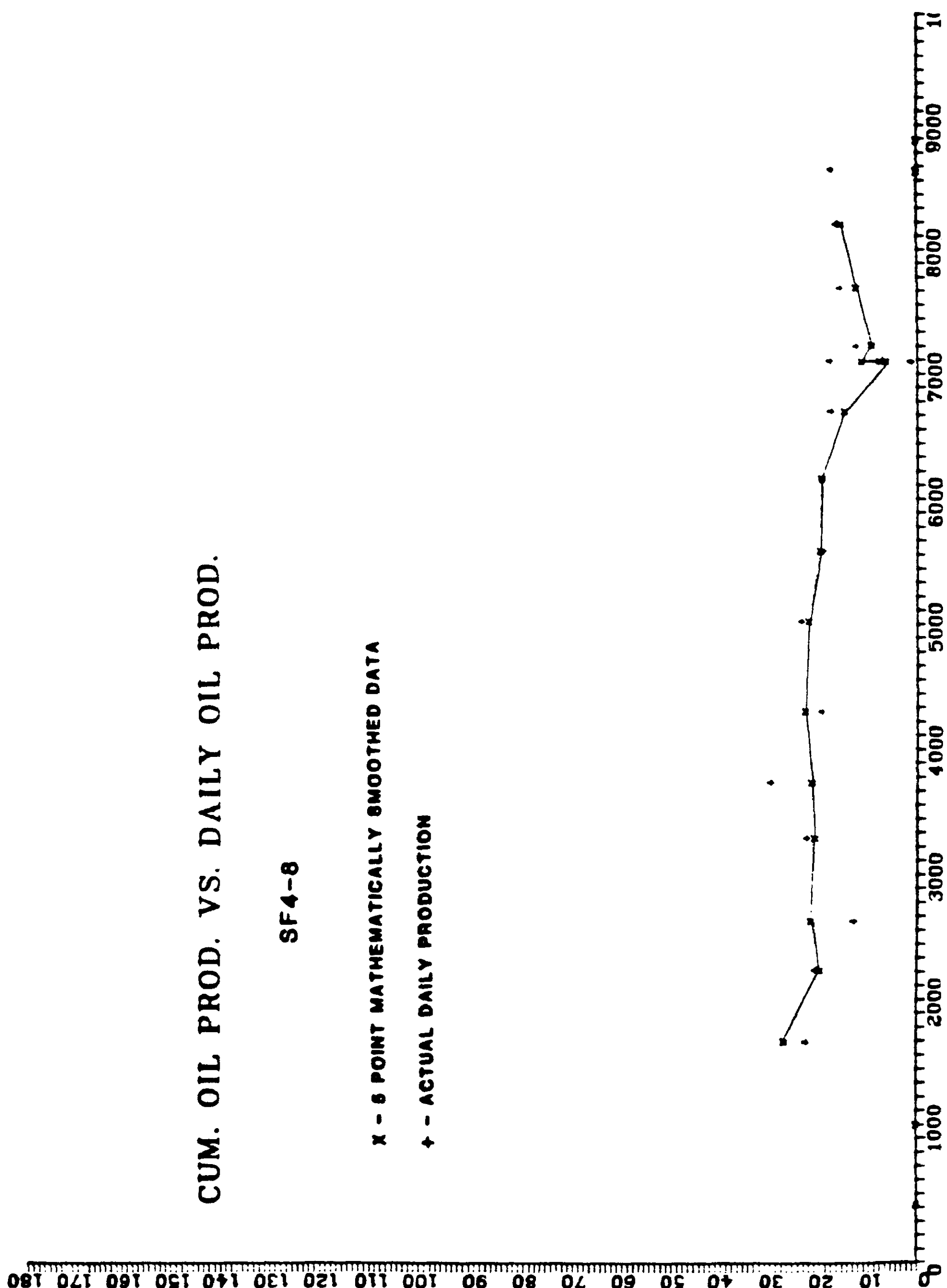
OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION
SF4-8



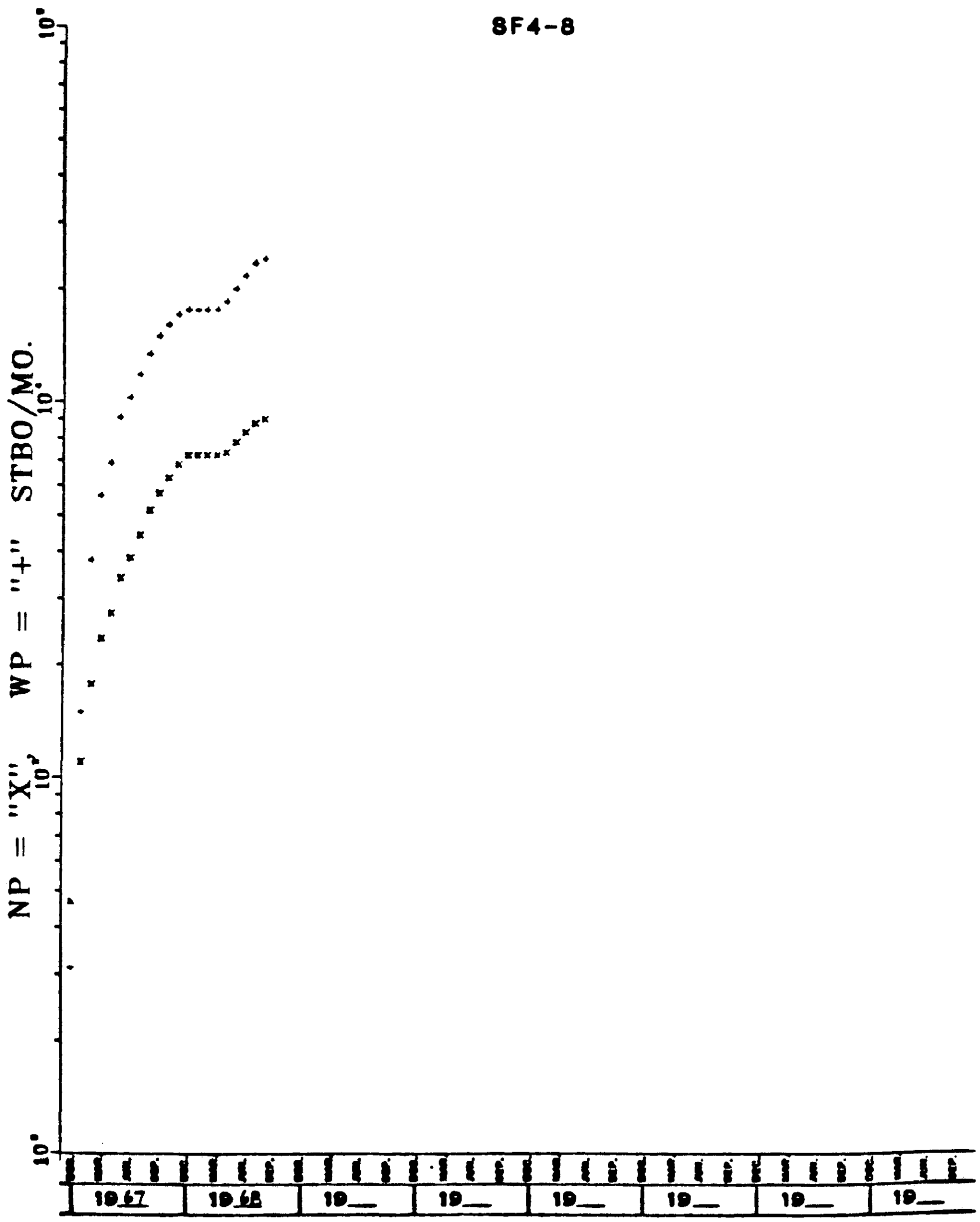

TIME VS. OIL CUT
SF4-8
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL CUT STBO/STB
0
10
20
30
40
50
60
70
80
90
100
1967
1968
19__
19__
19__
19__
19__
19__

TIME VS. WATER CUT



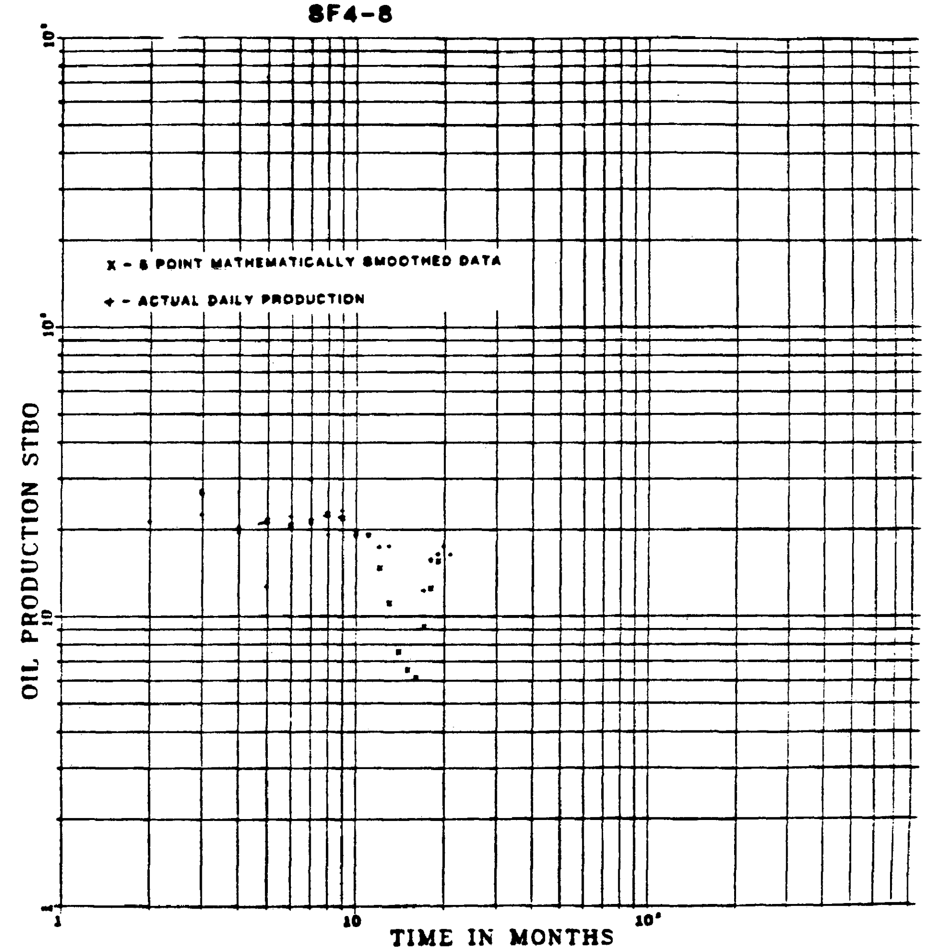

CUM. OIL PROD. VS. DAILY OIL PROD.
SF4-8
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
CUMULATIVE OIL PRODUCTION (Np)
OIL PROD STBO/D

TIME VS. CUM. OIL AND WATER PRODN.

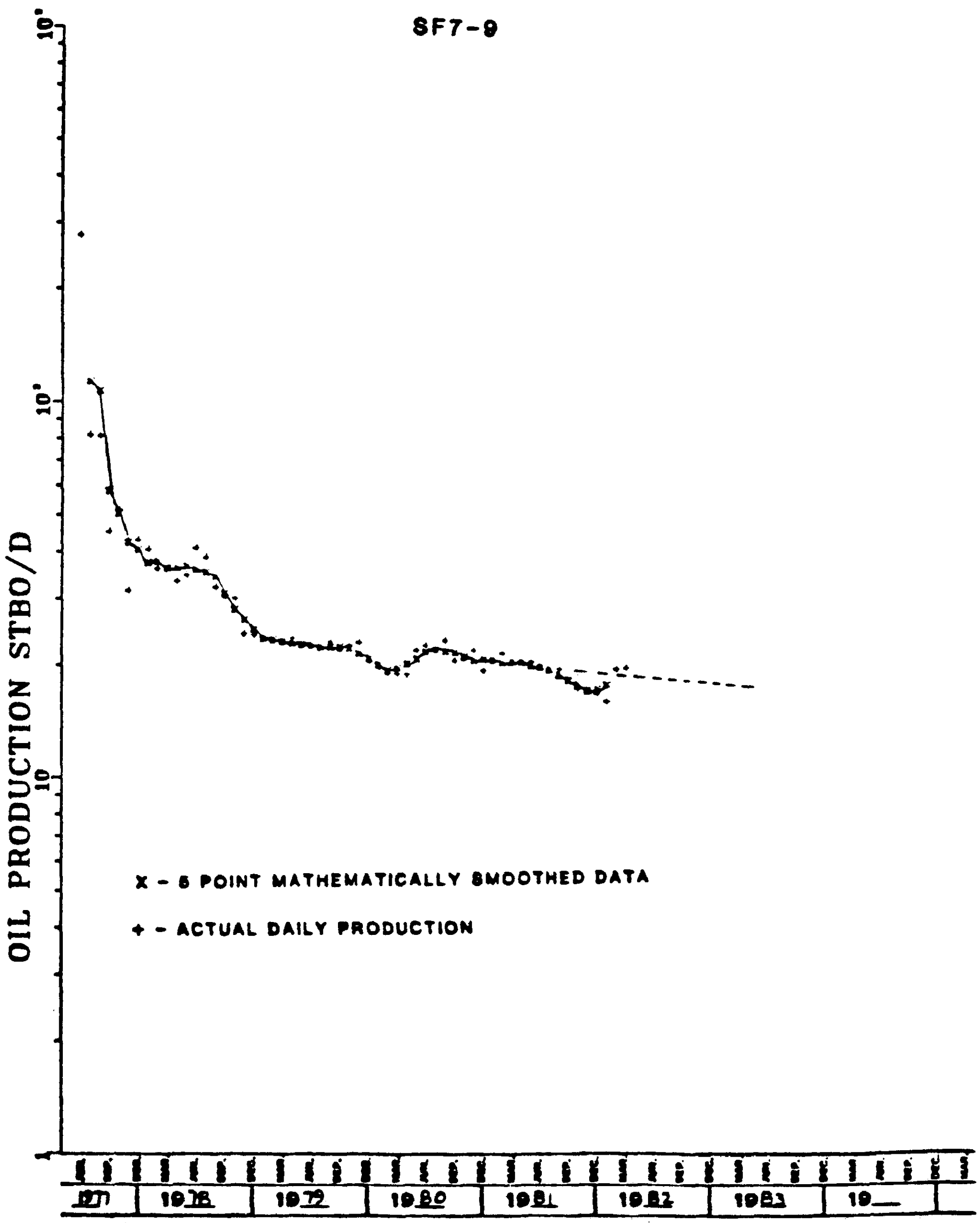


TIME VS. DAILY OIL PRODUCTION

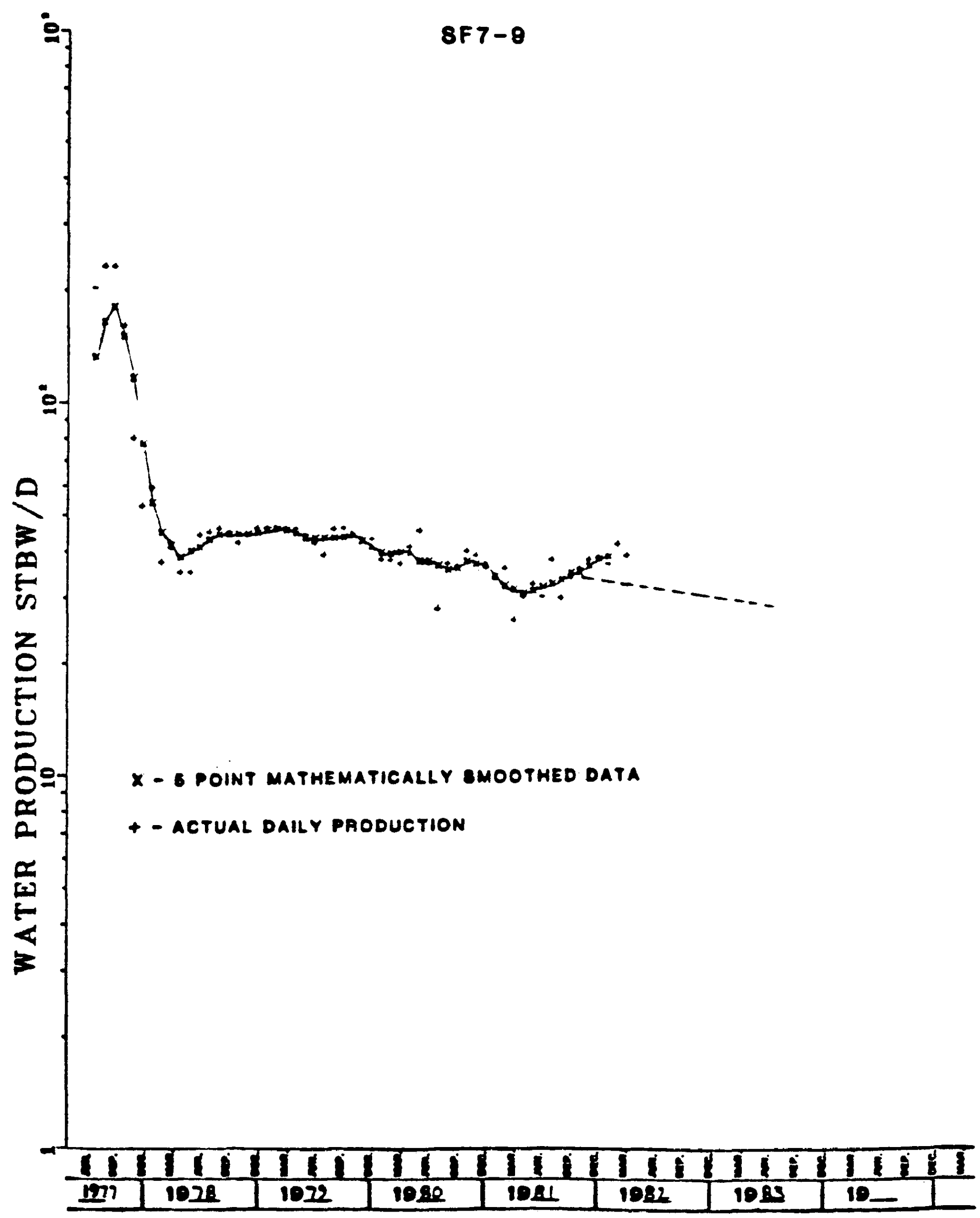
SF4-8



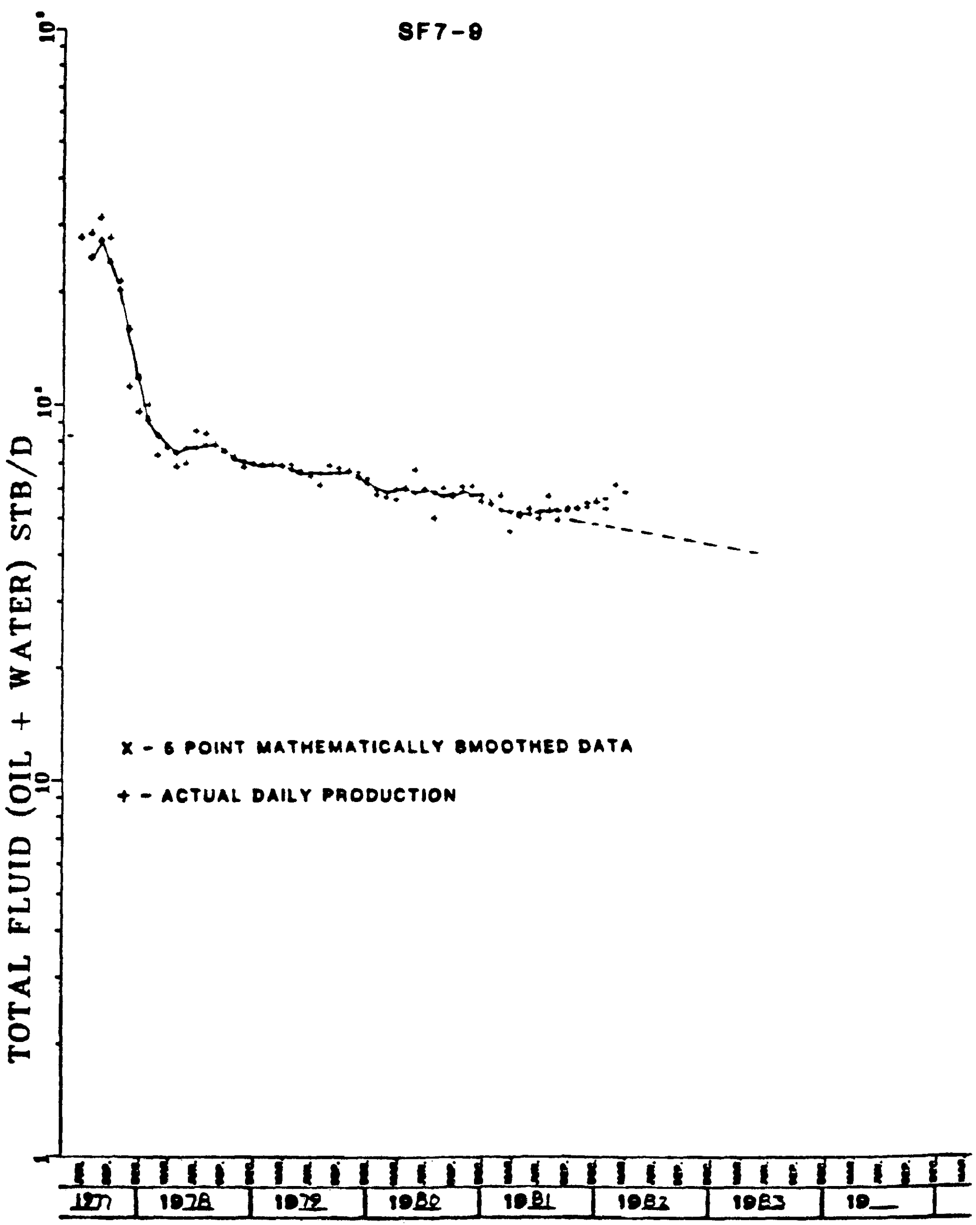
TIME VS. DAILY OIL PRODUCTION



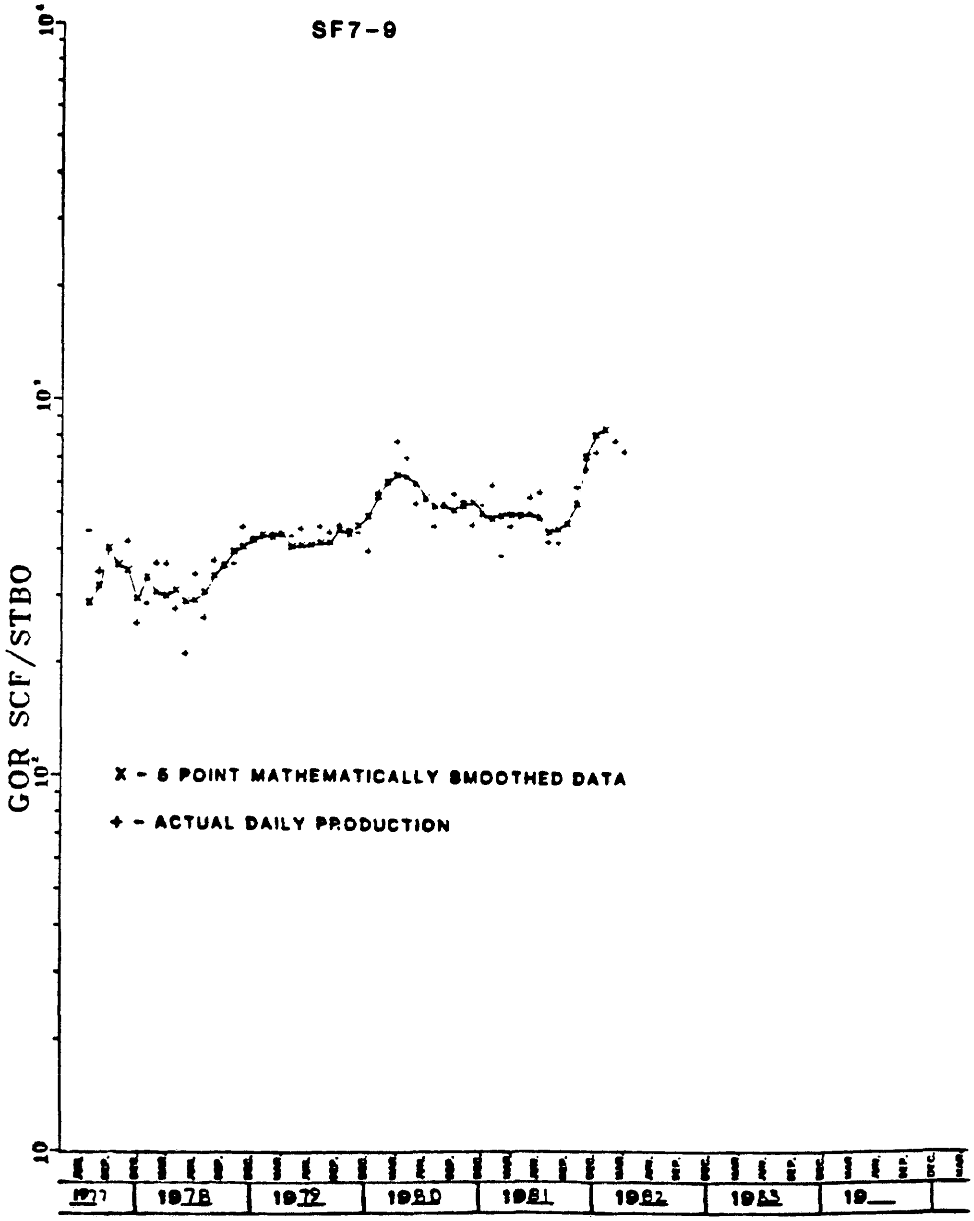
TIME VS. DAILY WATER PRODUCTION



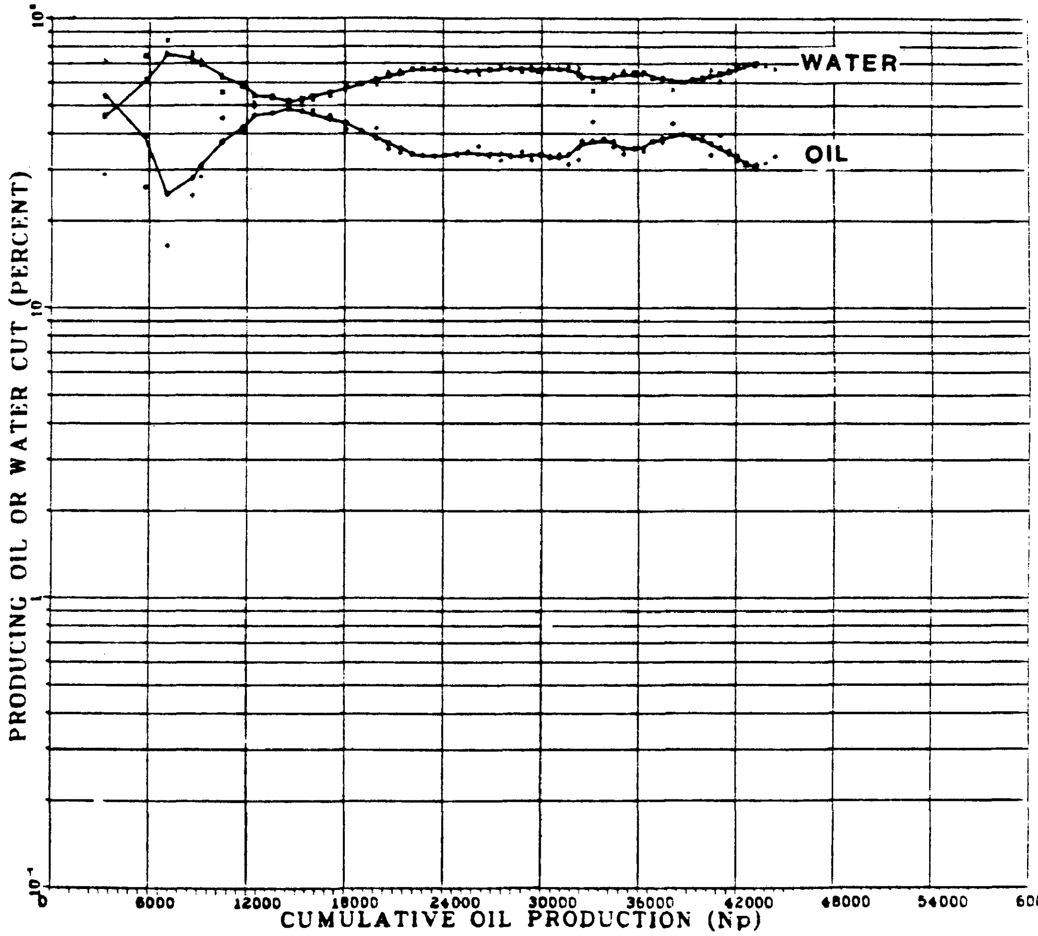
TIME VS. TOTAL FLUID PRODUCTION



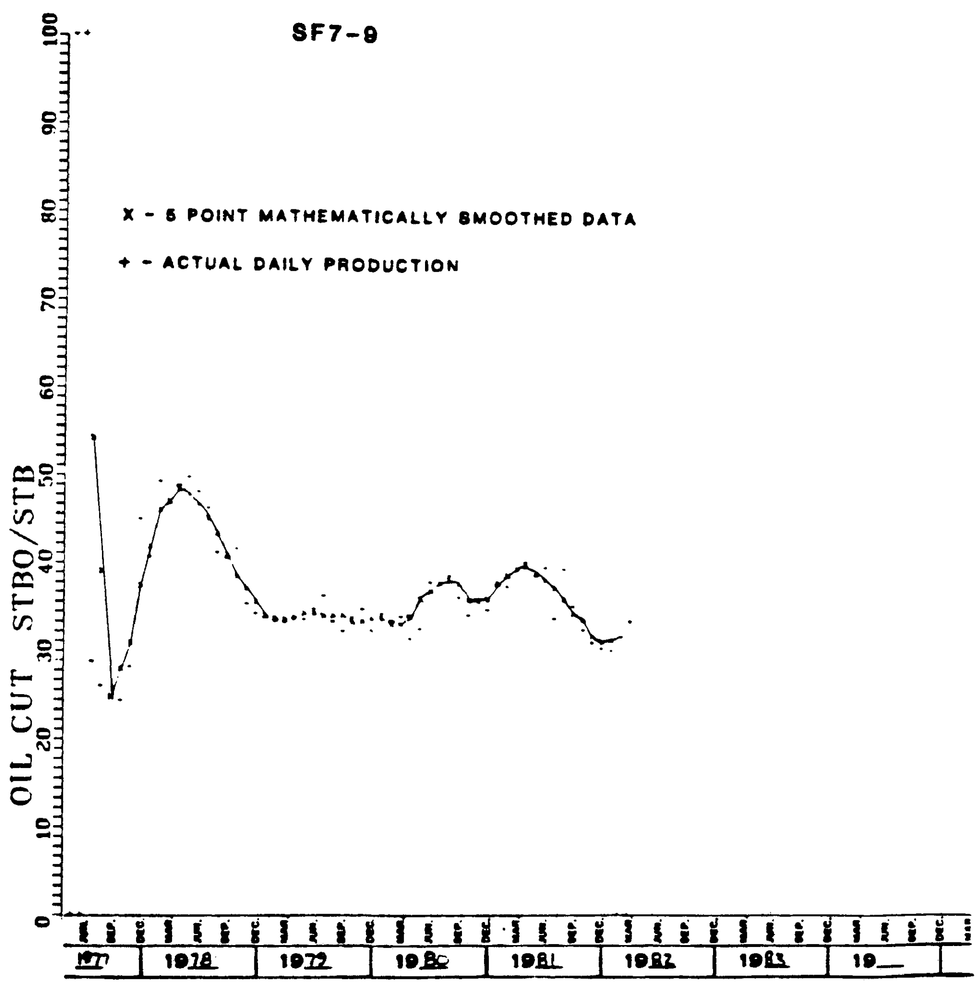
TIME VS. GAS OIL RATIO

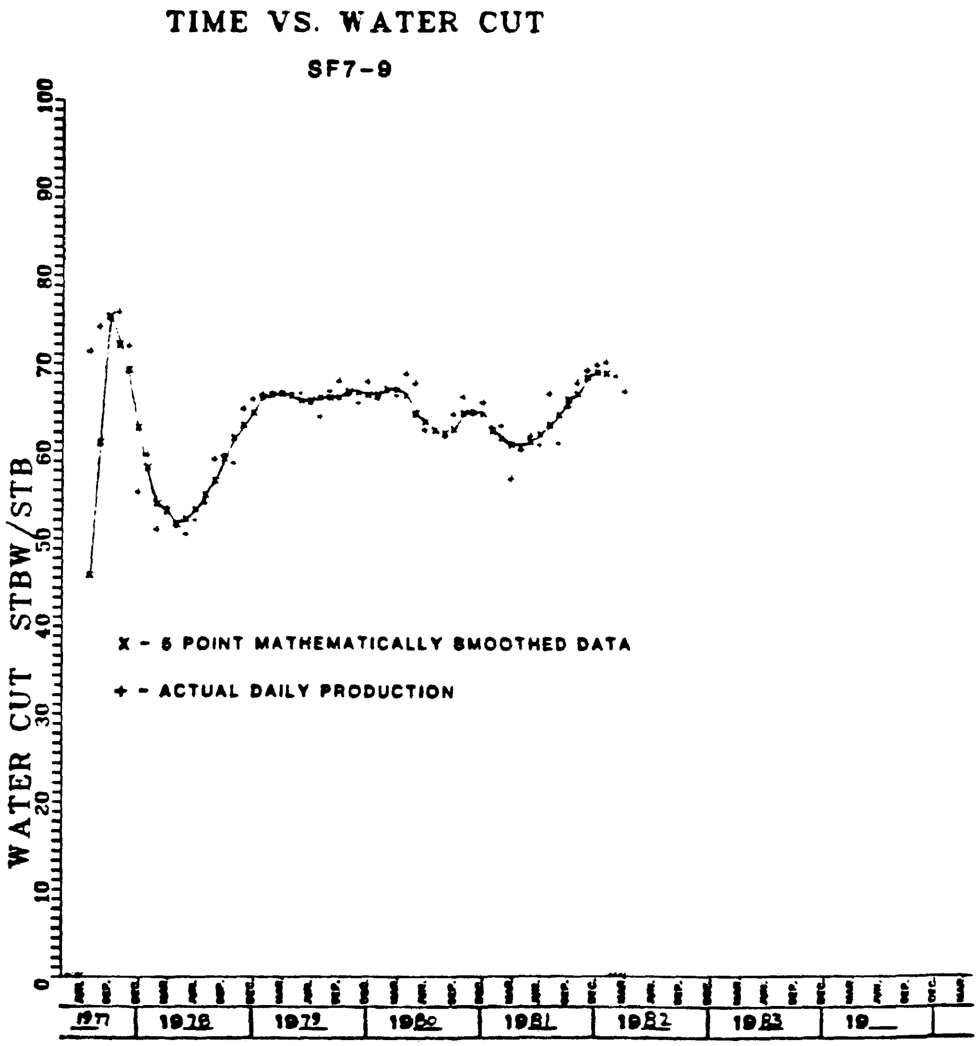


OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION
SF7-9

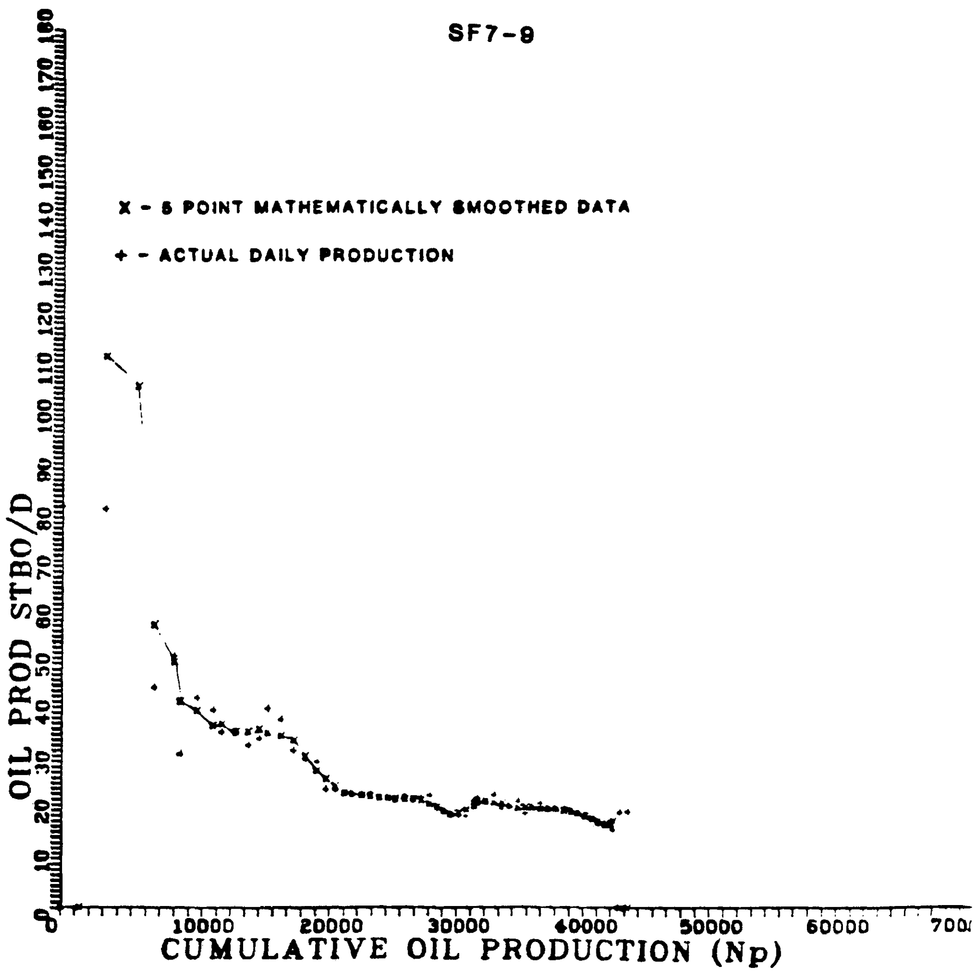


TIME VS. OIL CUT

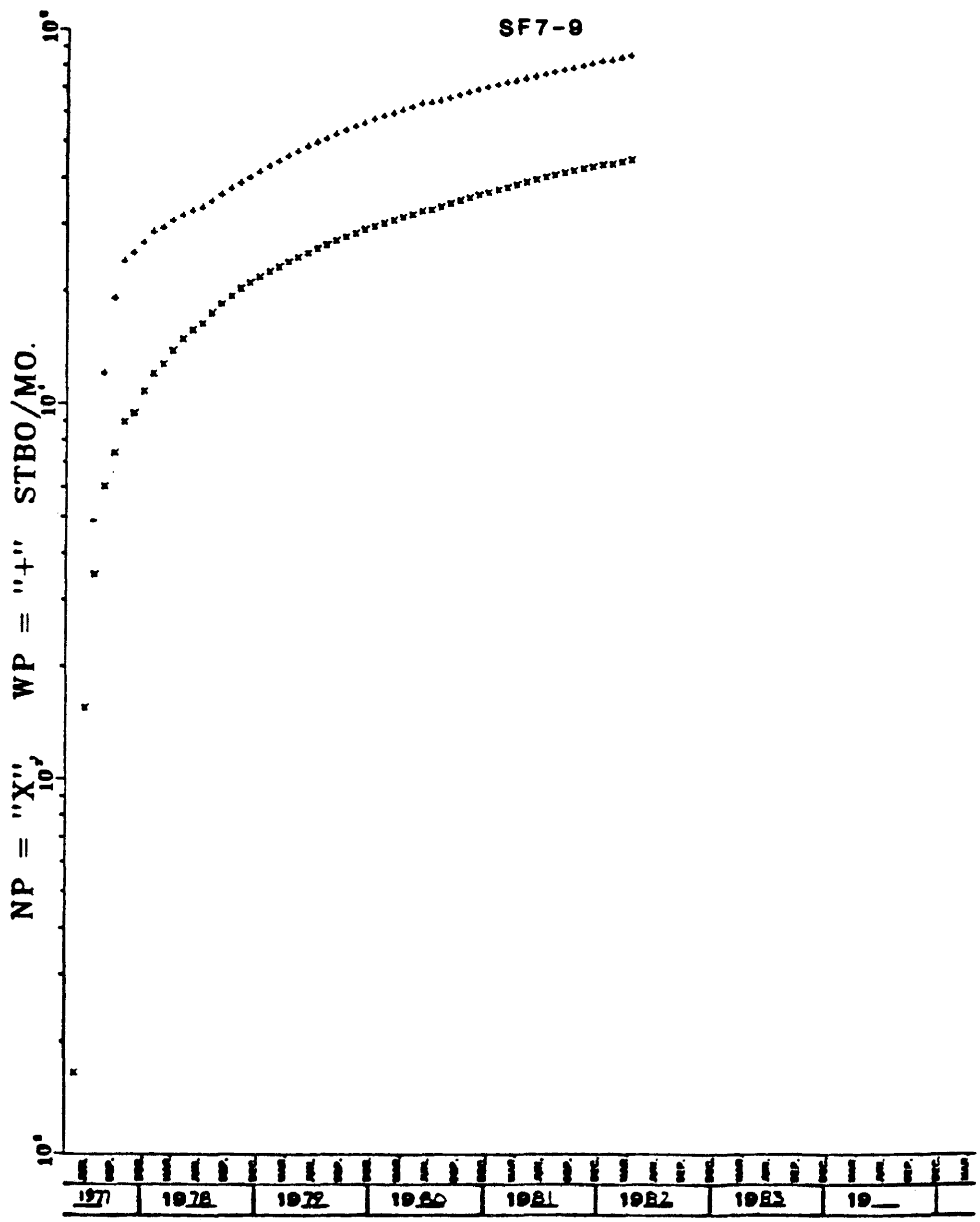


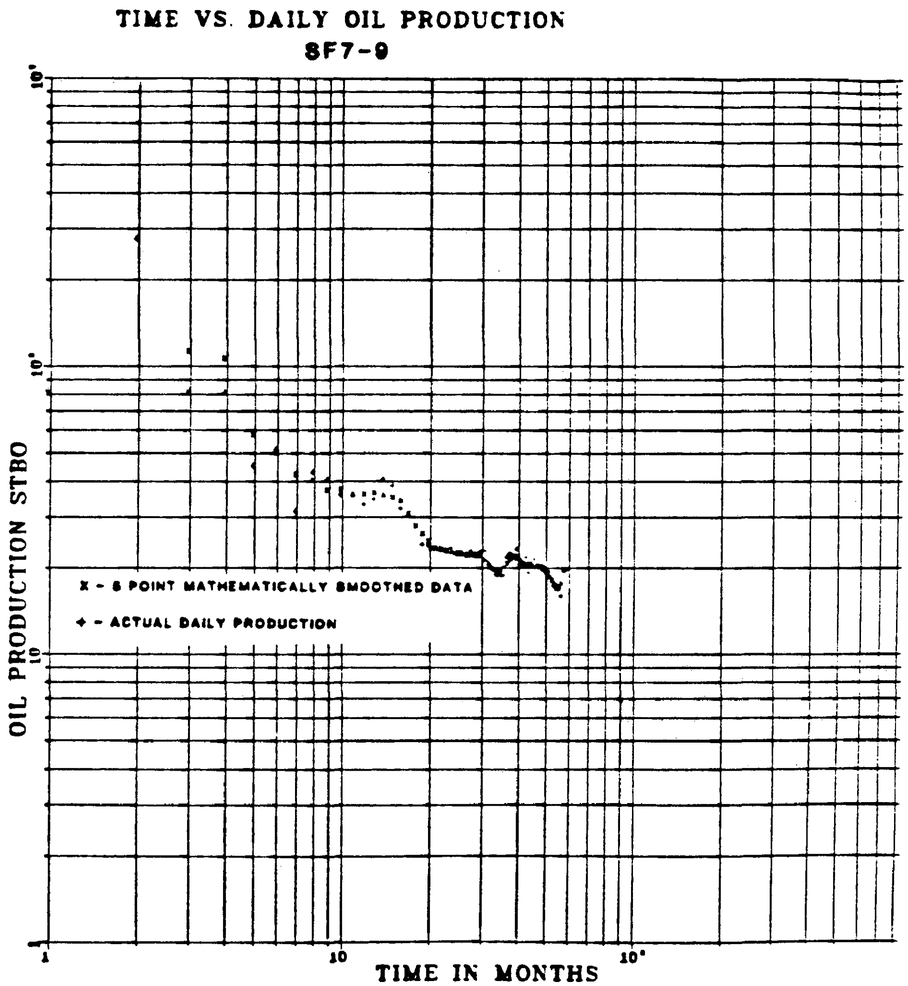

TIME VS. WATER CUT
SF7-9
WATER CUT STBW/STB
0
10
20
30
40
50
60
70
80
90
100
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
1977
1978
1979
1980
1981
1982
1983
19__

CUM. OIL PROD. VS. DAILY OIL PROD.

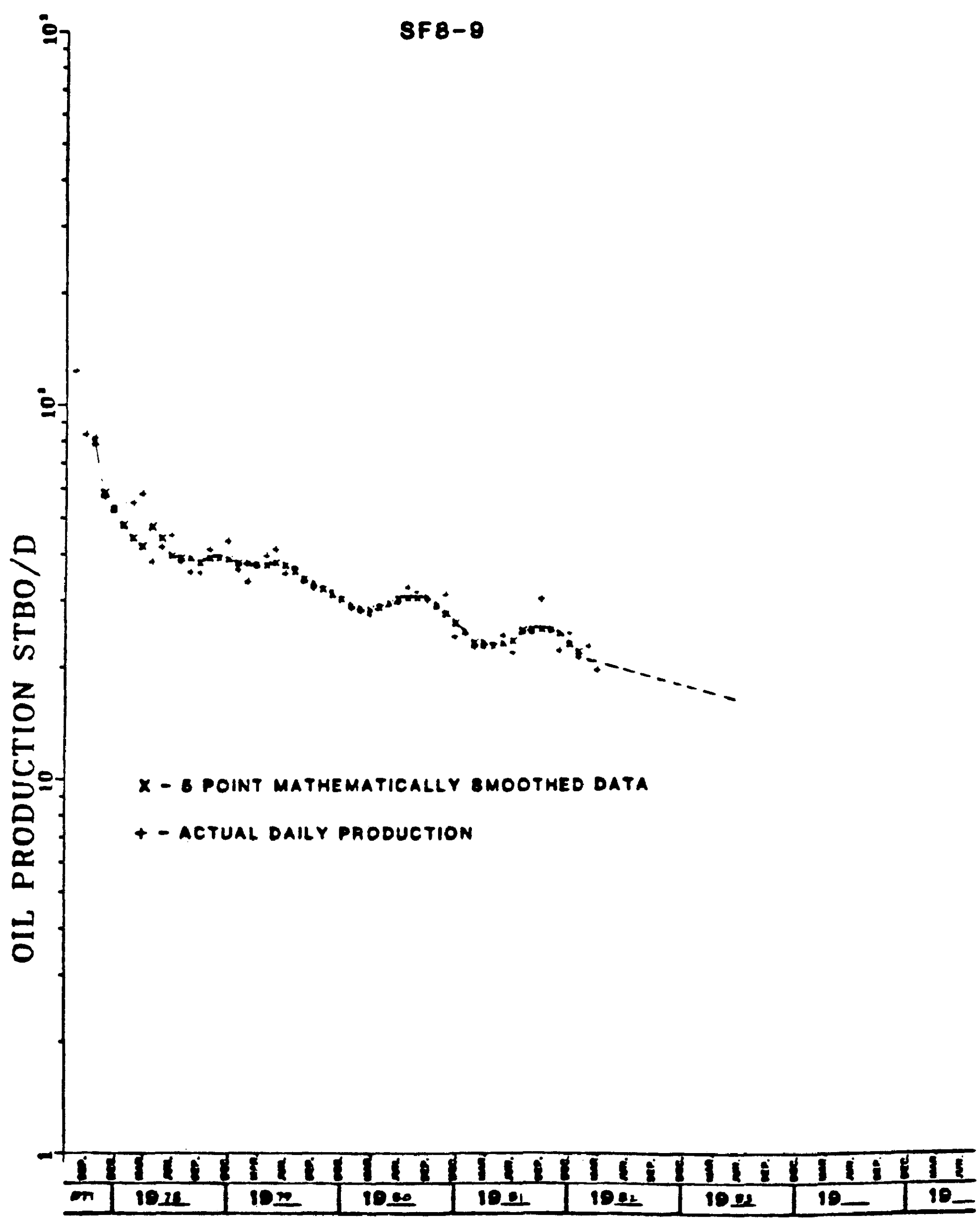


TIME VS. CUM. OIL AND WATER PRODN.

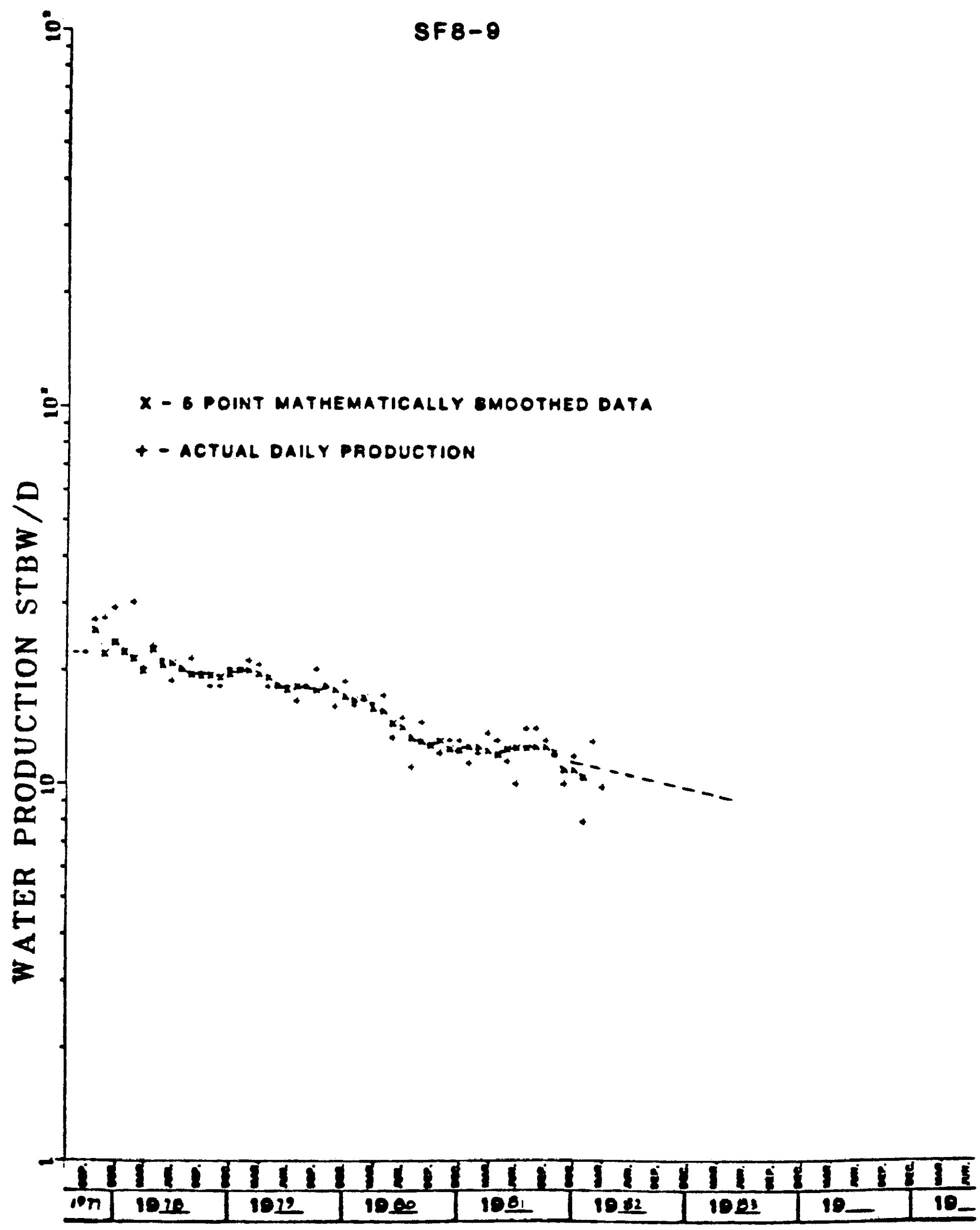



TIME VS. DAILY OIL PRODUCTION
SF7-9
OIL PRODUCTION STBO
TIME IN MONTHS
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION

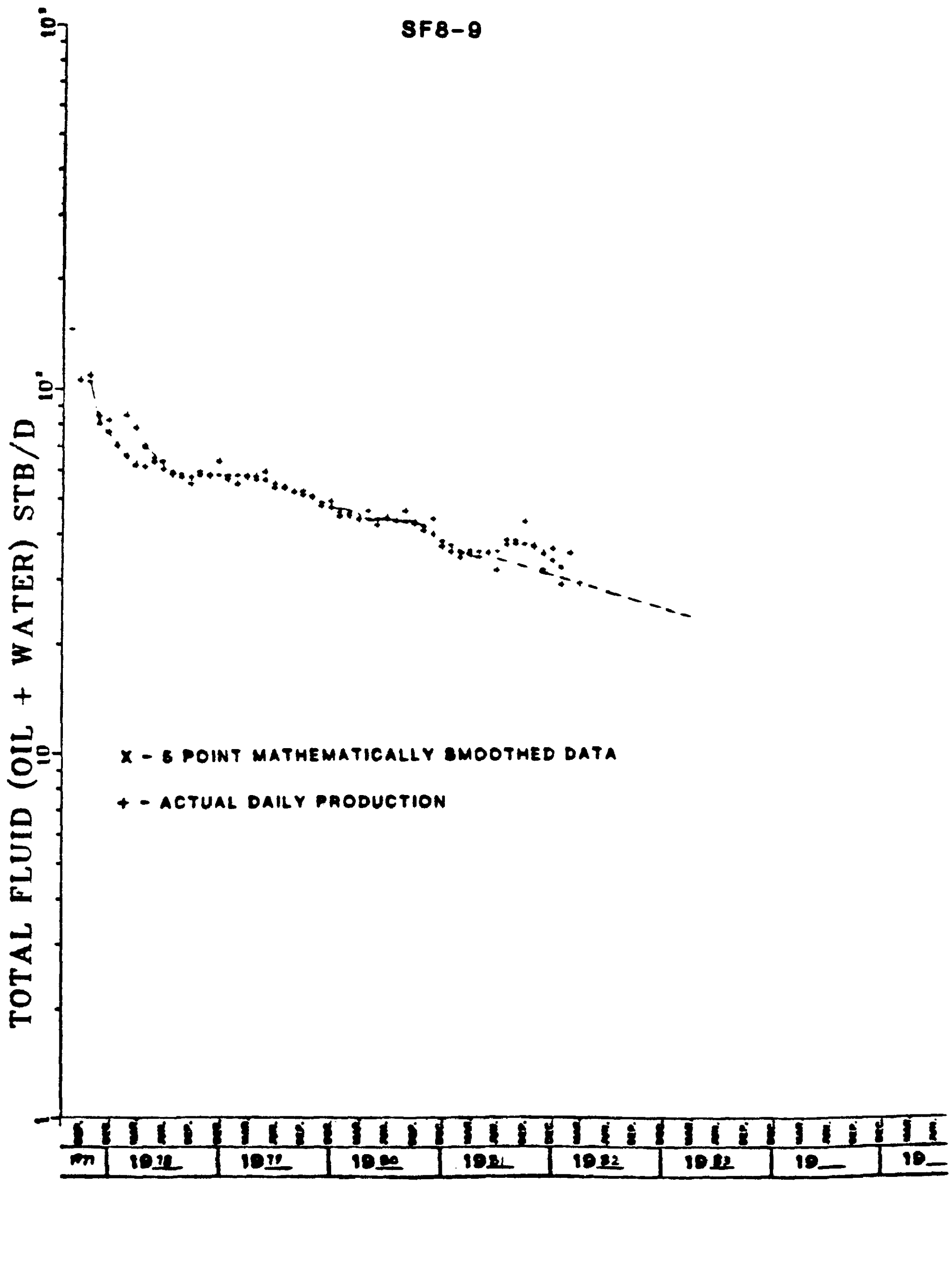
TIME VS. DAILY OIL PRODUCTION

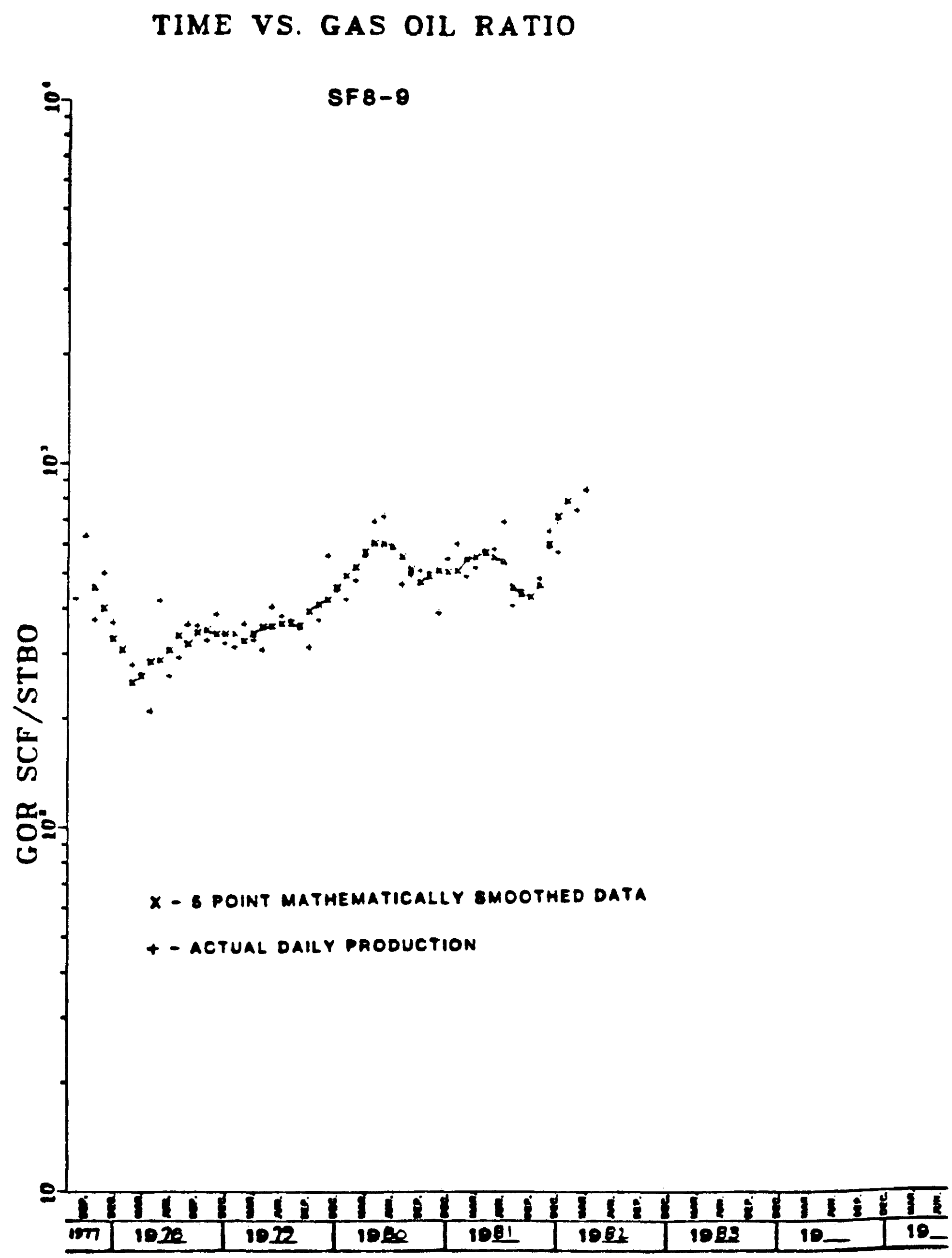


TIME VS. DAILY WATER PRODUCTION

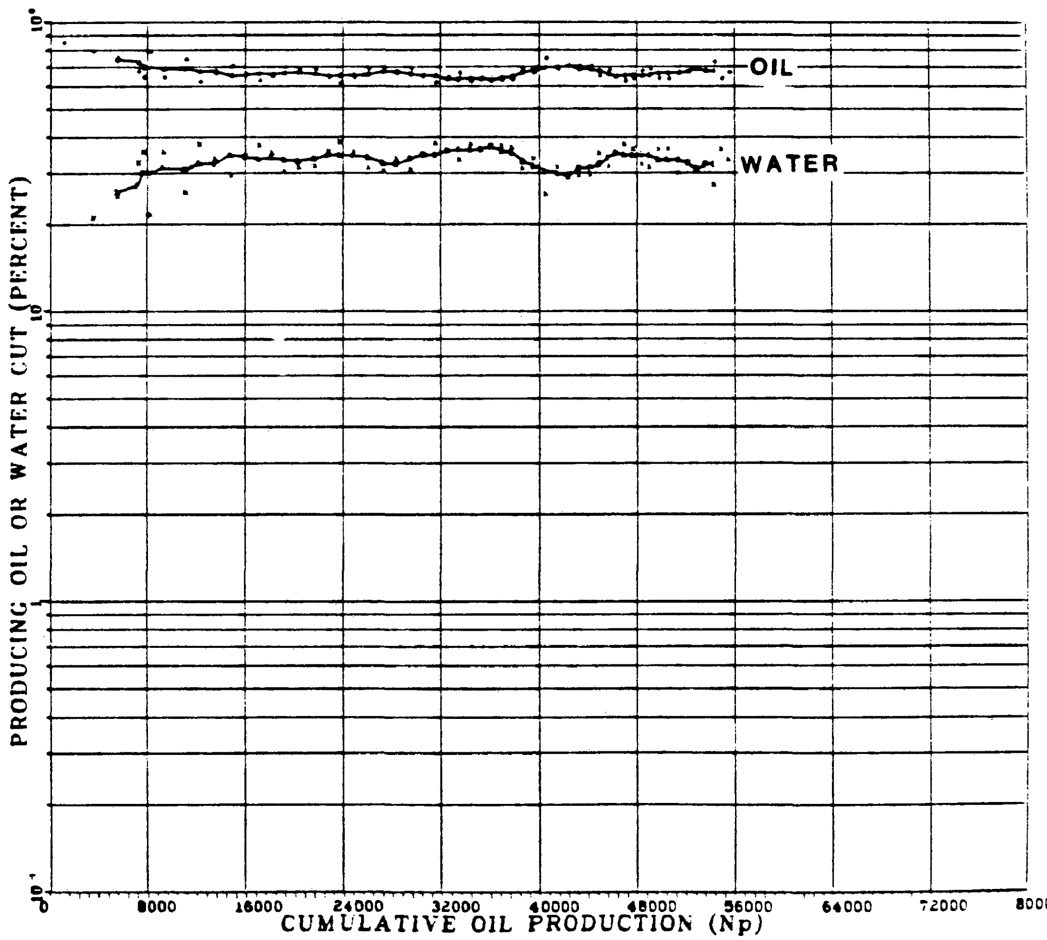


TIME VS. TOTAL FLUID PRODUCTION

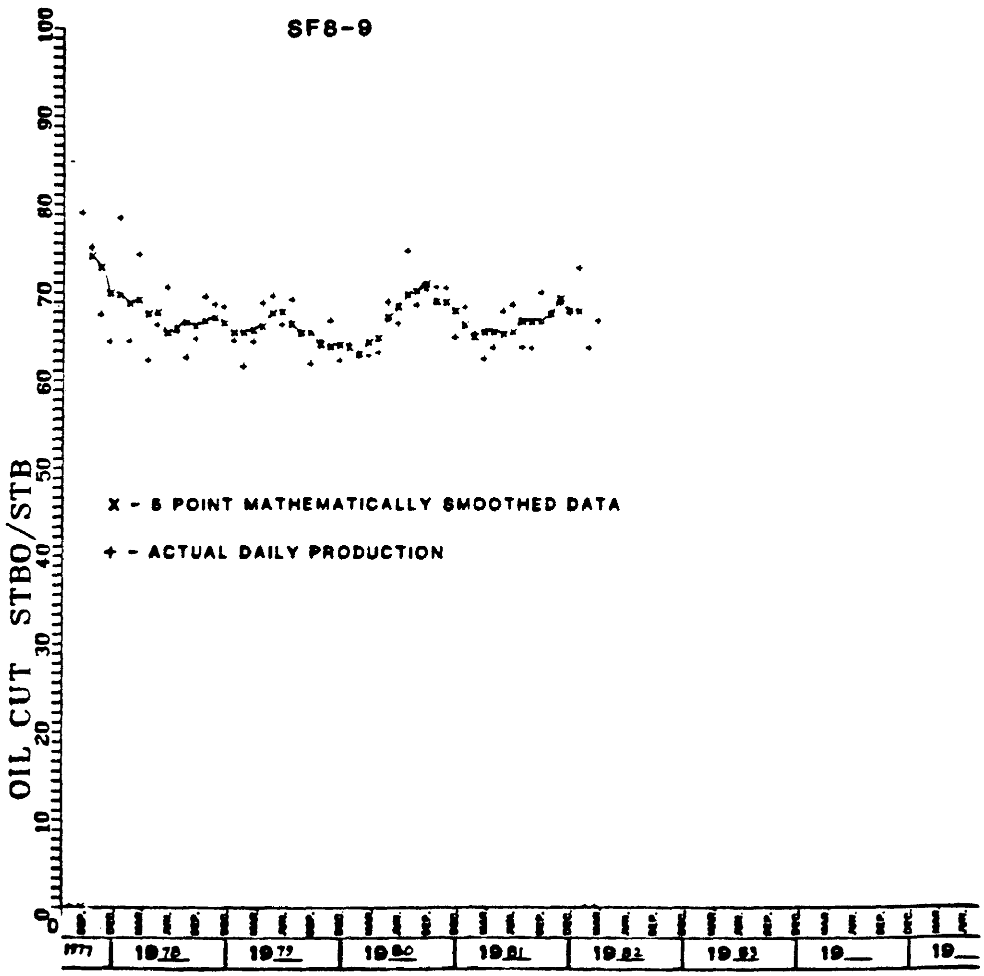



TIME VS. GAS OIL RATIO
SF8-9
GOR SCF/STBO
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
1977
1978
1979
1980
1981
1982
1983
19__
19__

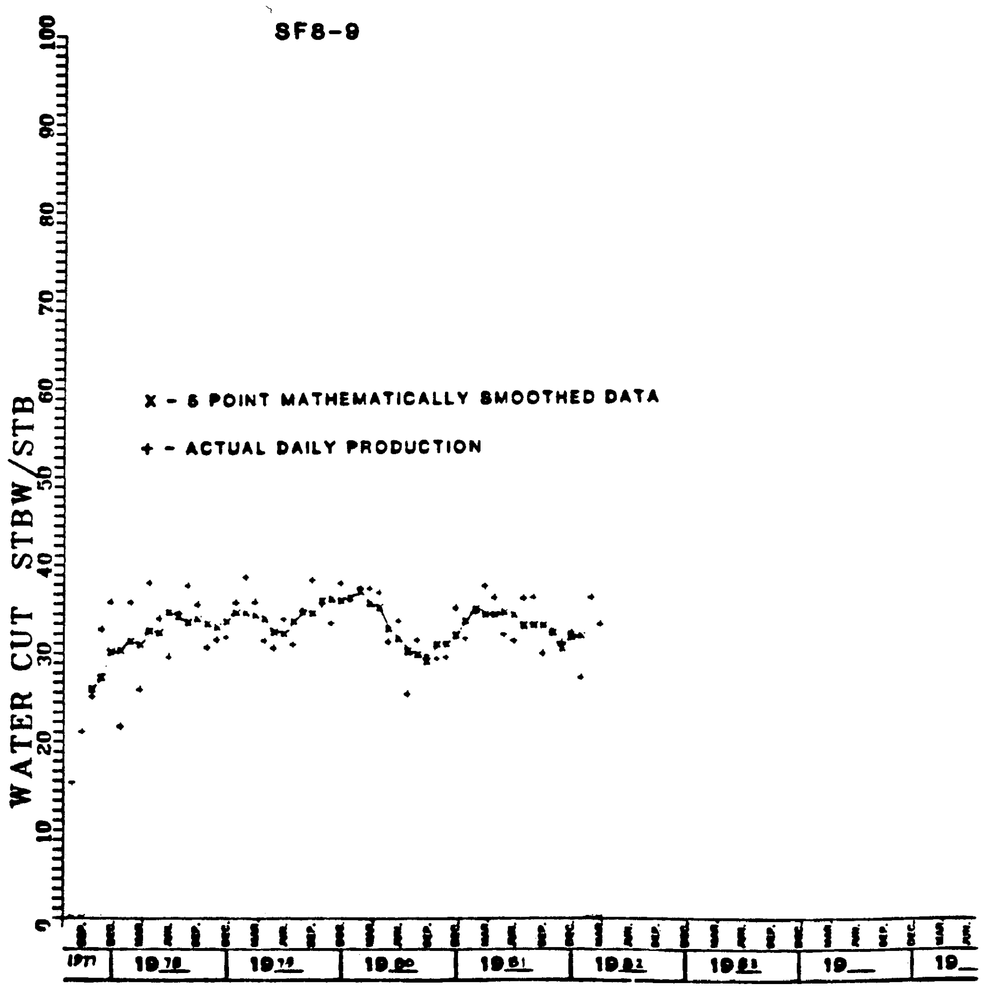
OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION
SF8-9



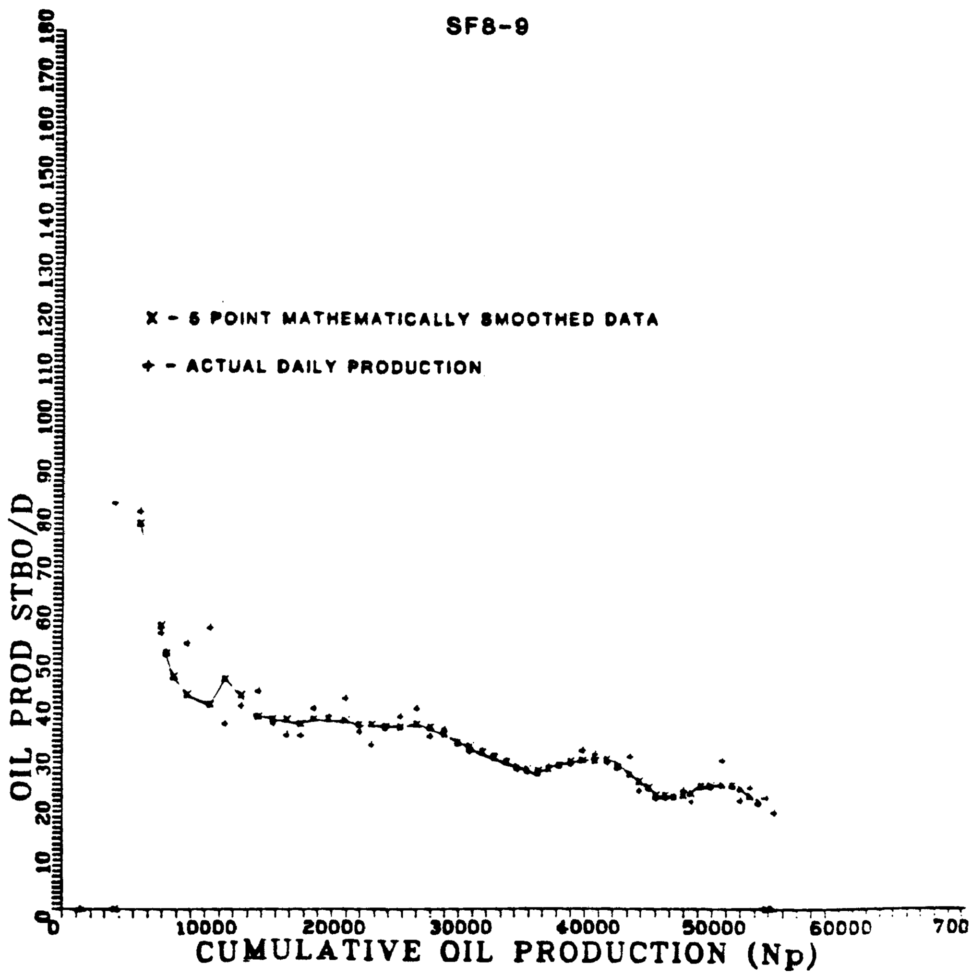
TIME VS. OIL CUT

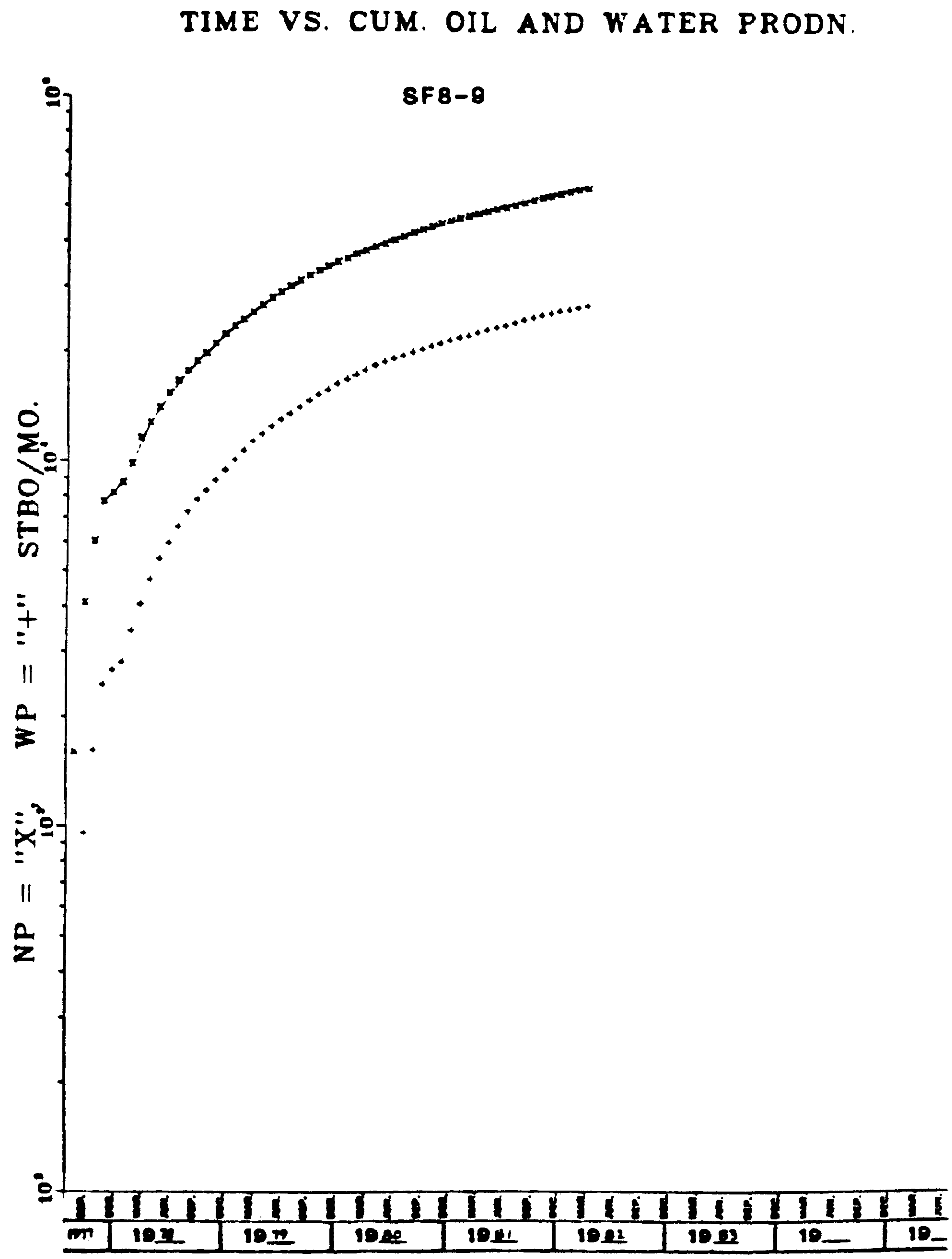


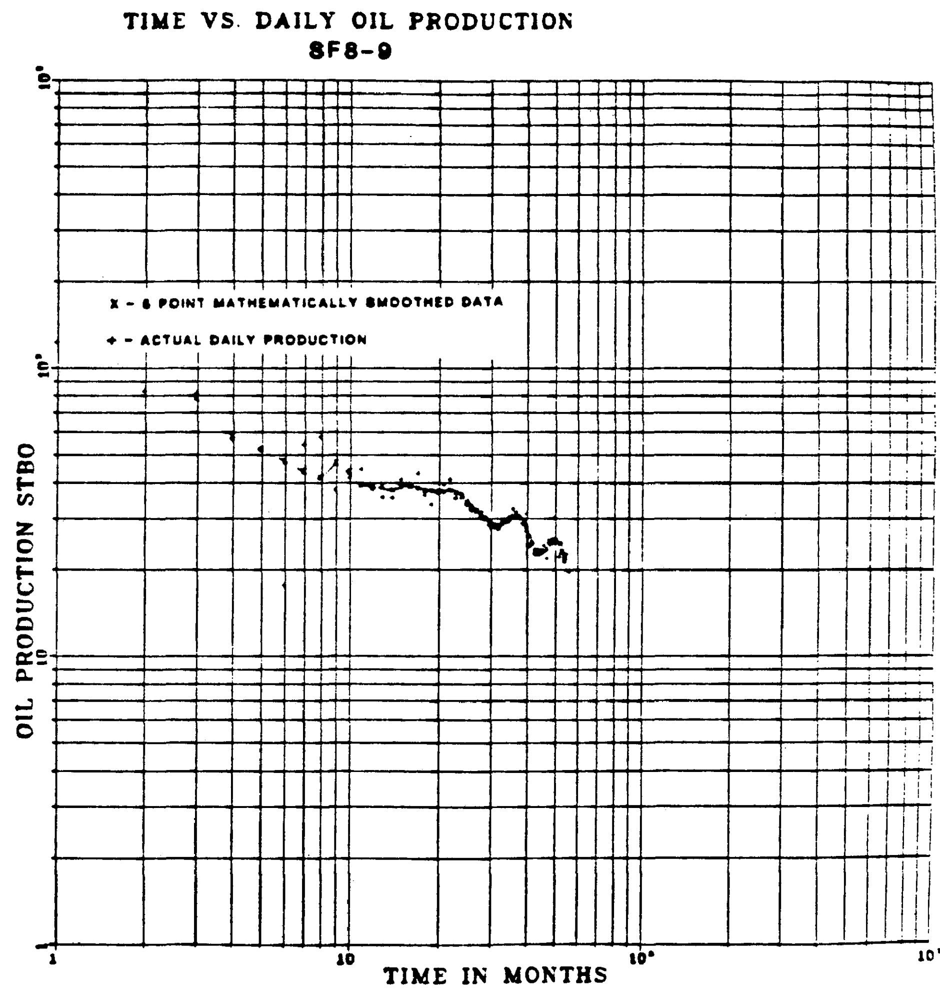
TIME VS. WATER CUT



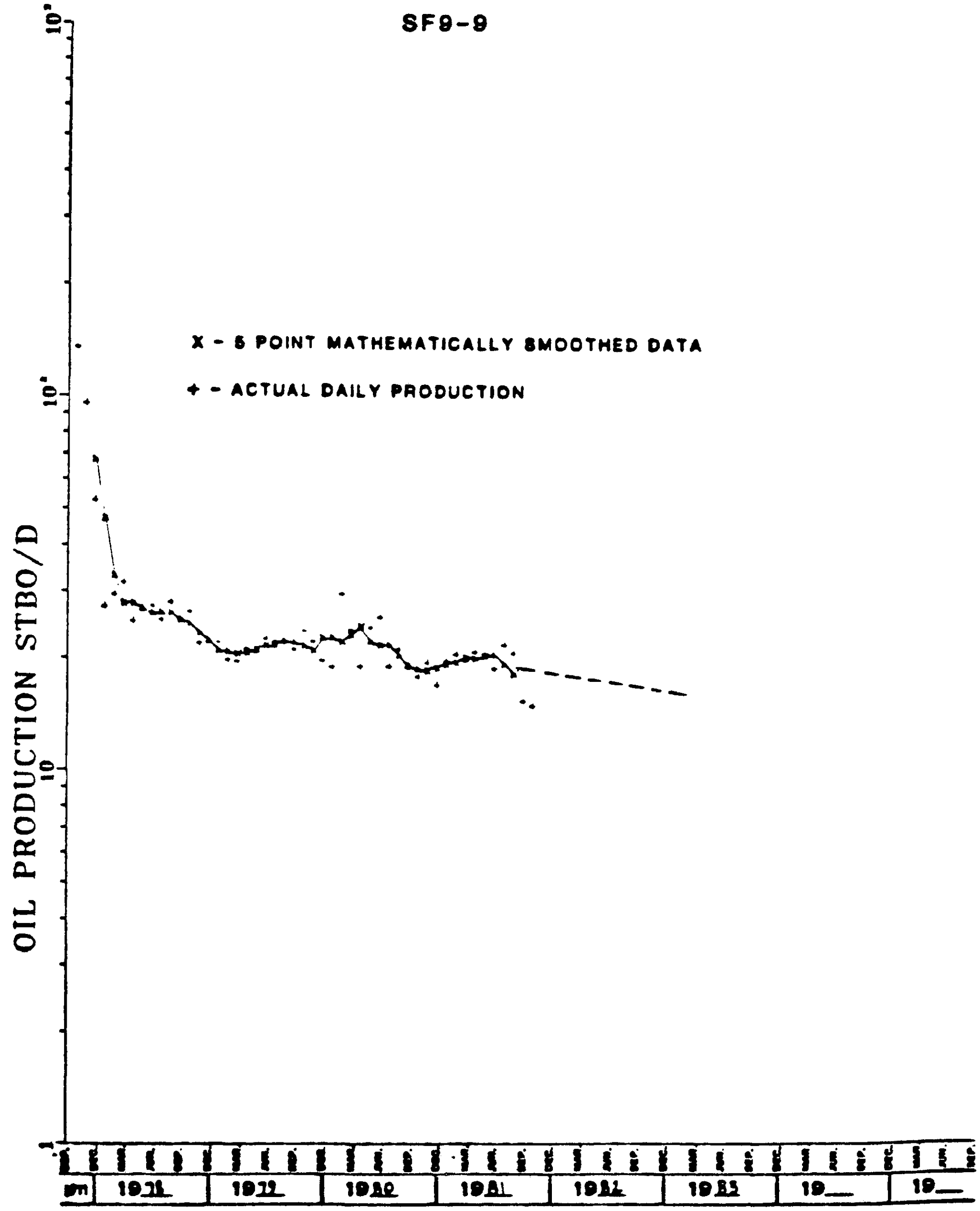
CUM. OIL PROD. VS. DAILY OIL PROD.



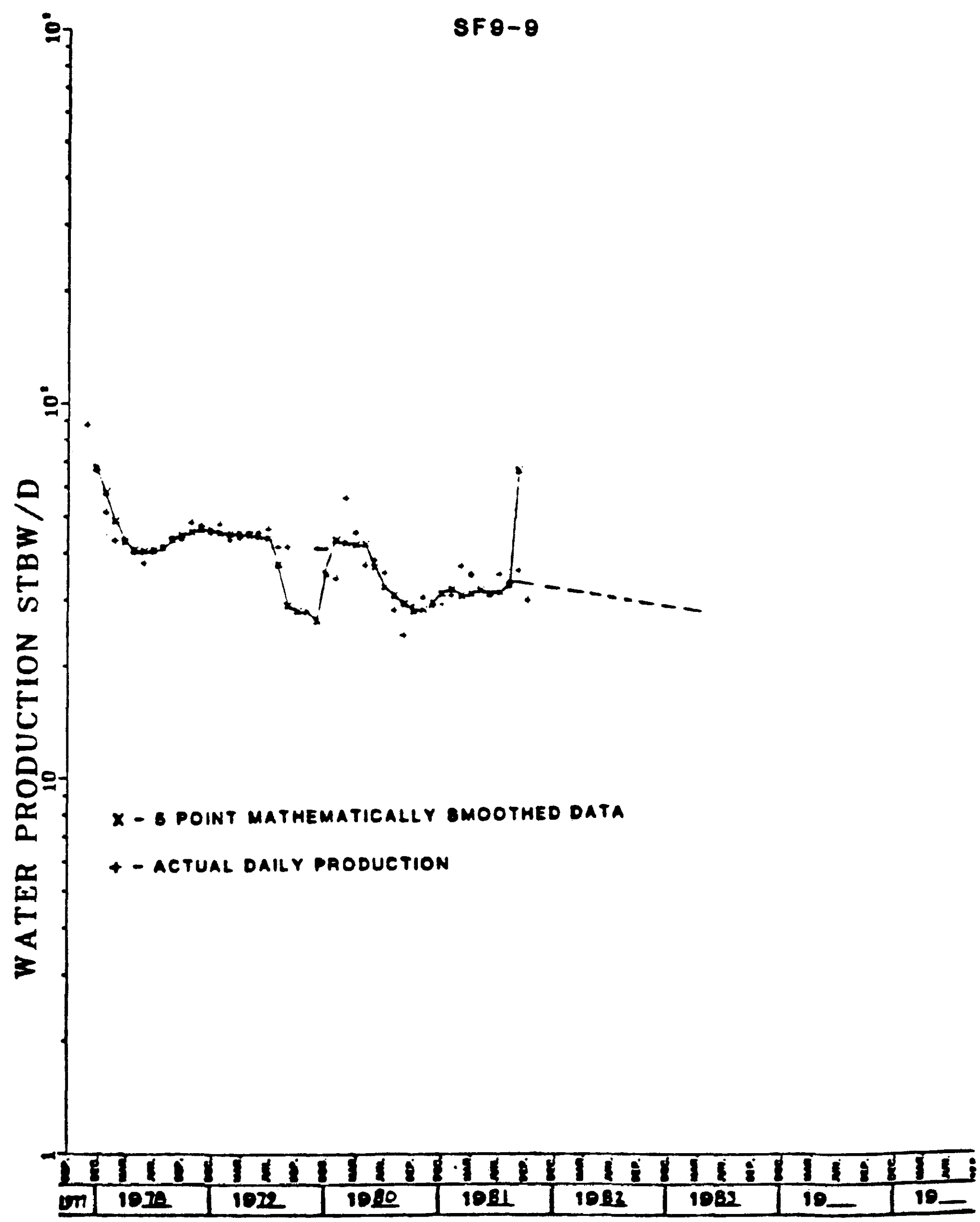

TIME VS. CUM. OIL AND WATER PRODN.
SF8-9
NP = "X" WP = "+" STBO/MO.
10
10
10
10
1978
1979
1980
1981
1982
1983
19__
19__


TIME VS. DAILY OIL PRODUCTION
SF8-9
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL PRODUCTION STBO
TIME IN MONTHS

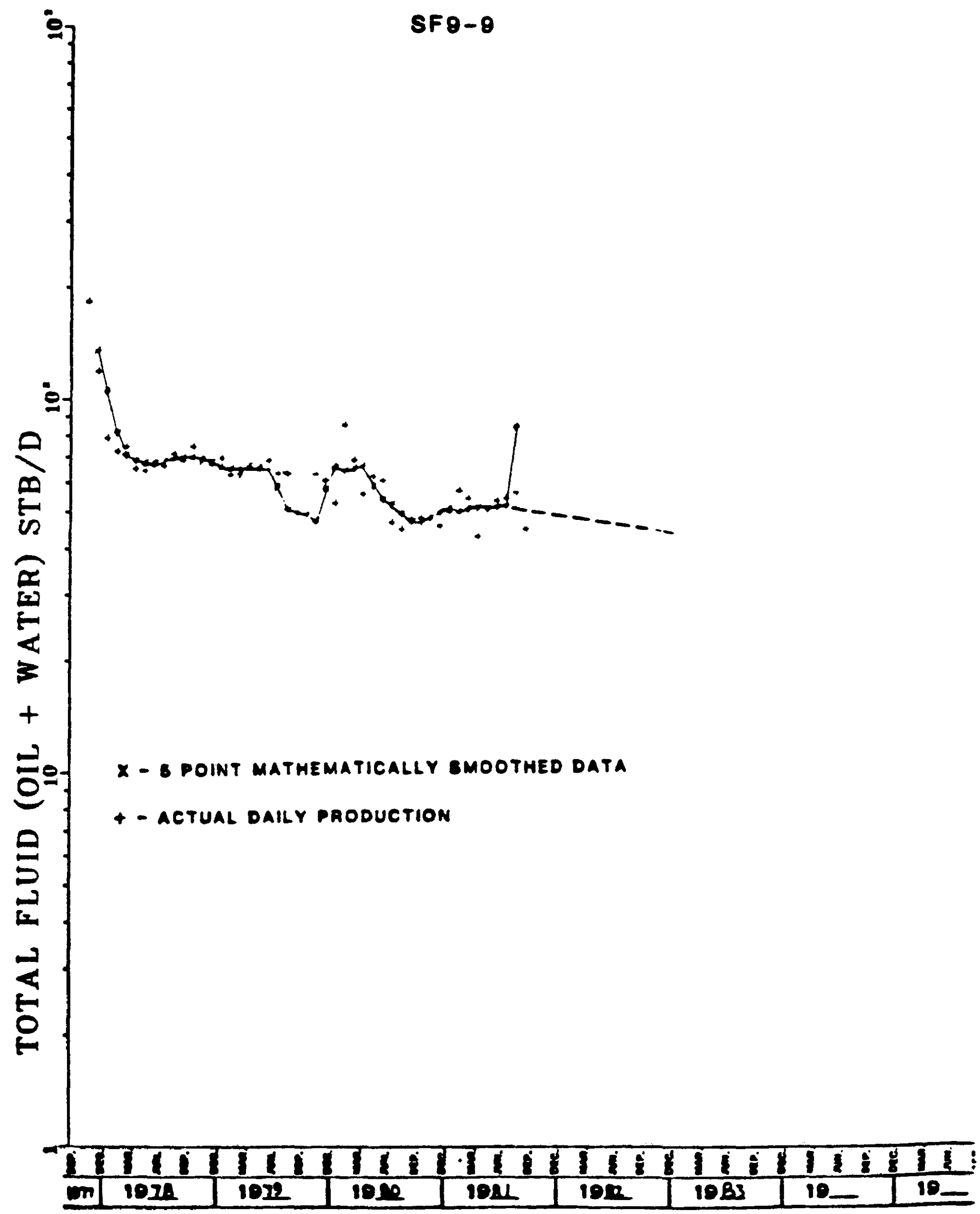
TIME VS. DAILY OIL PRODUCTION



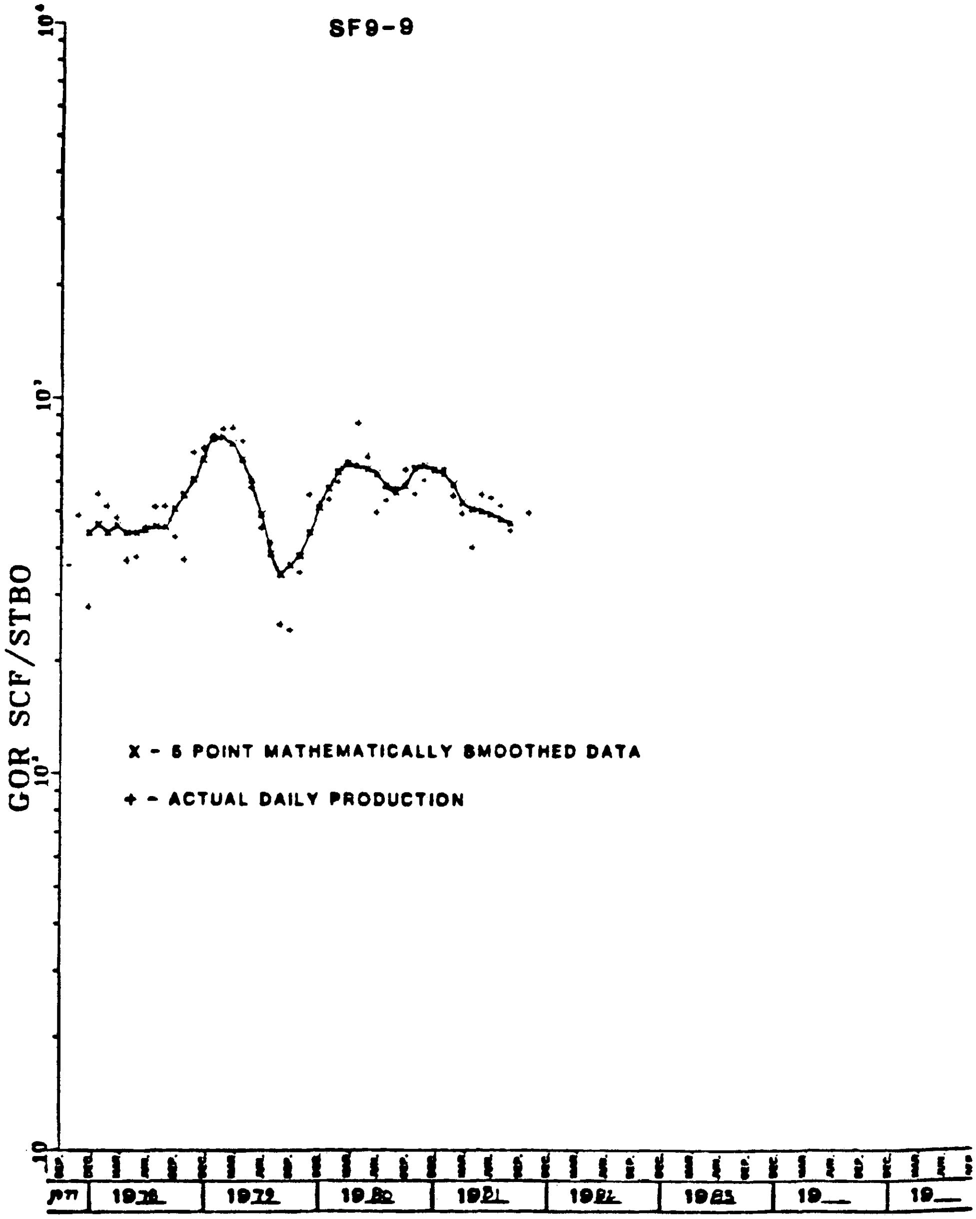
TIME VS. DAILY WATER PRODUCTION



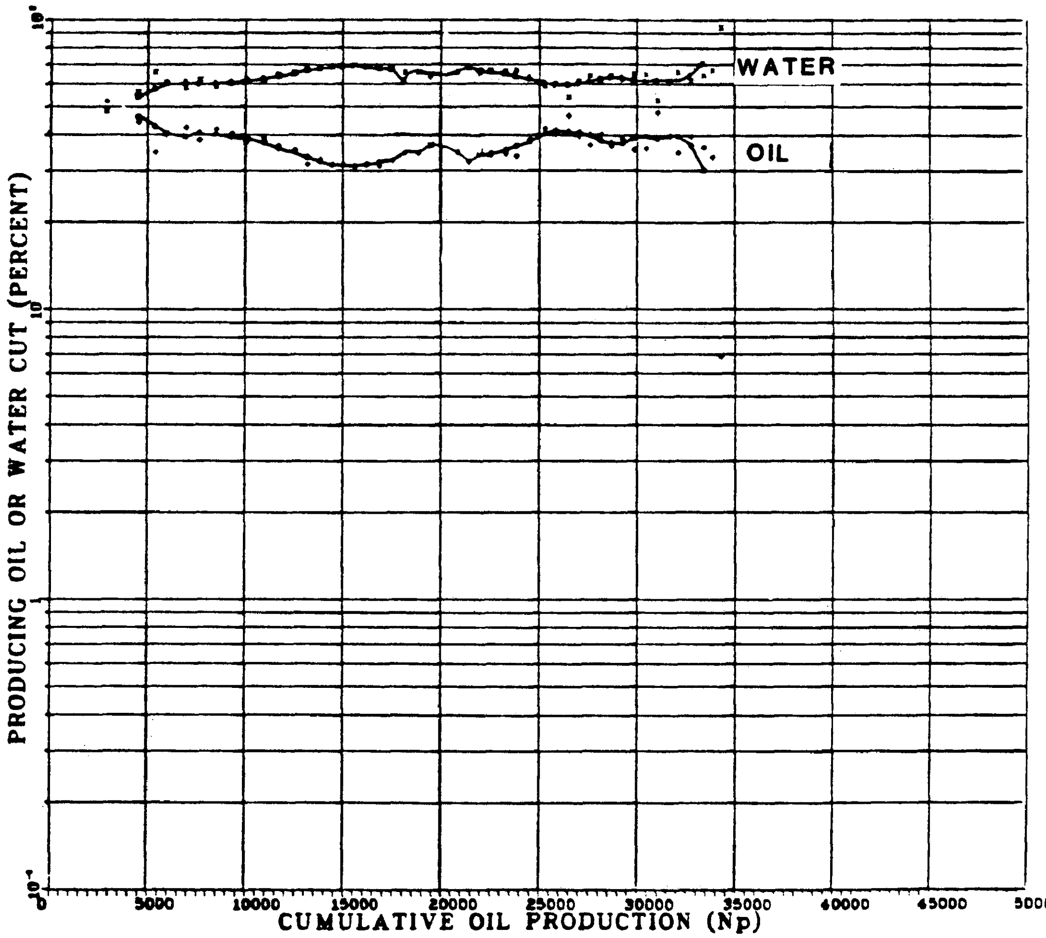
TIME VS. TOTAL FLUID PRODUCTION



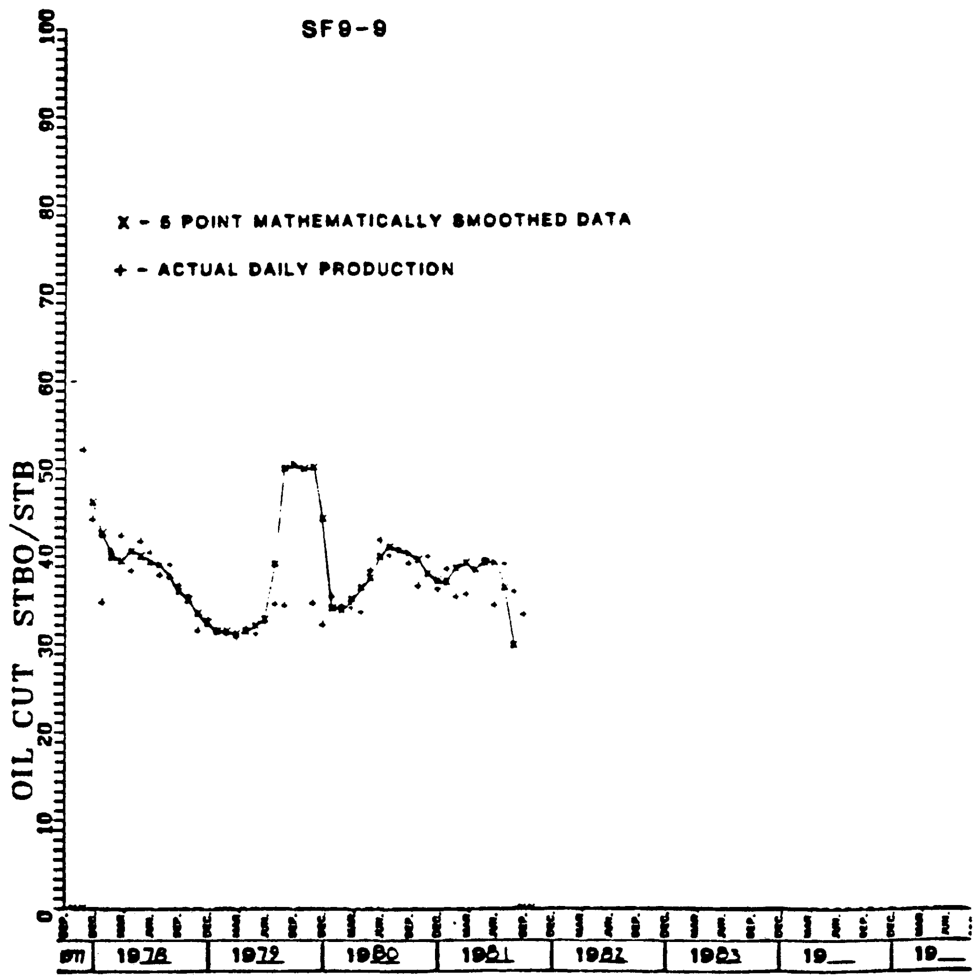
TIME VS. GAS OIL RATIO



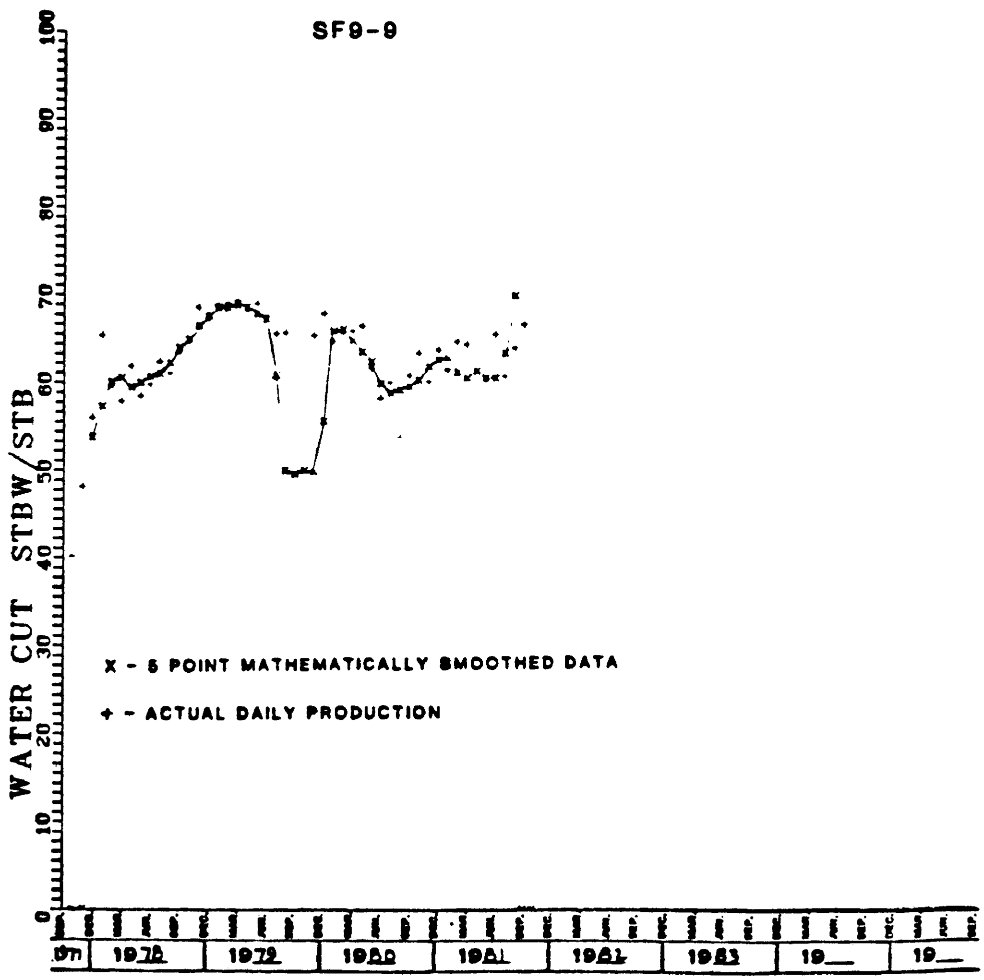
OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION
SF9-9



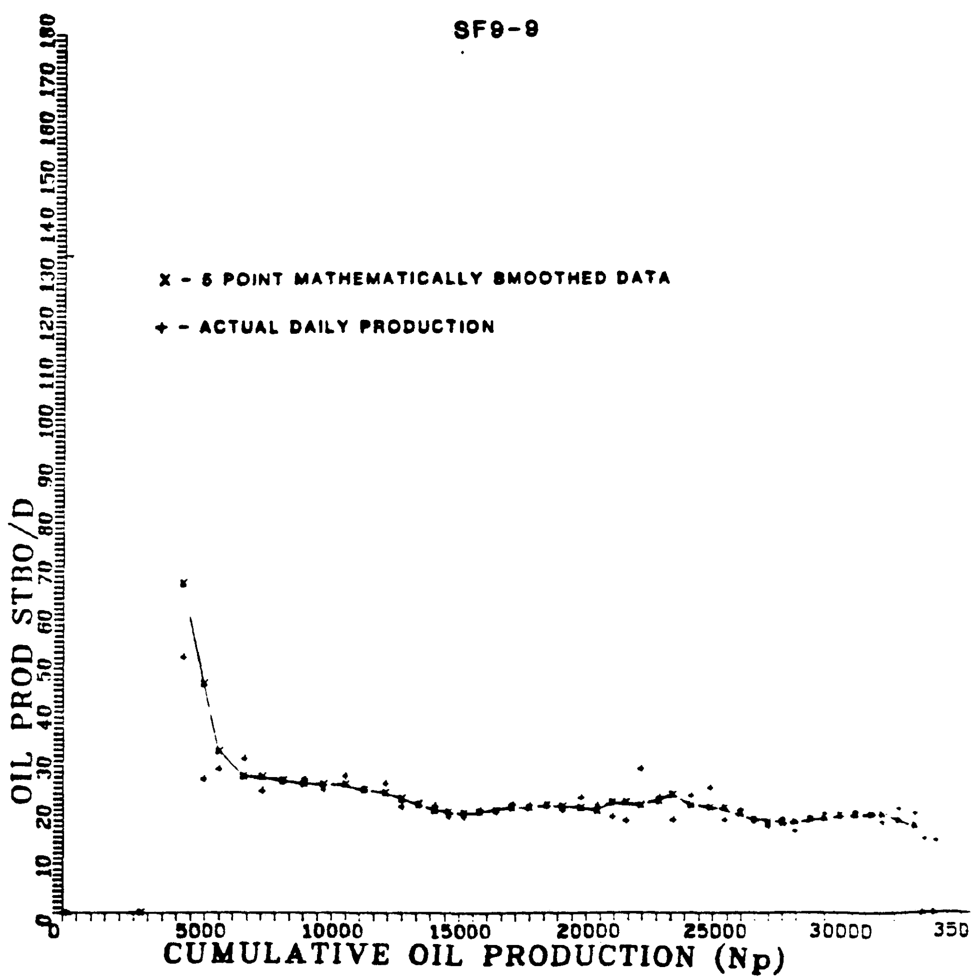
TIME VS. OIL CUT



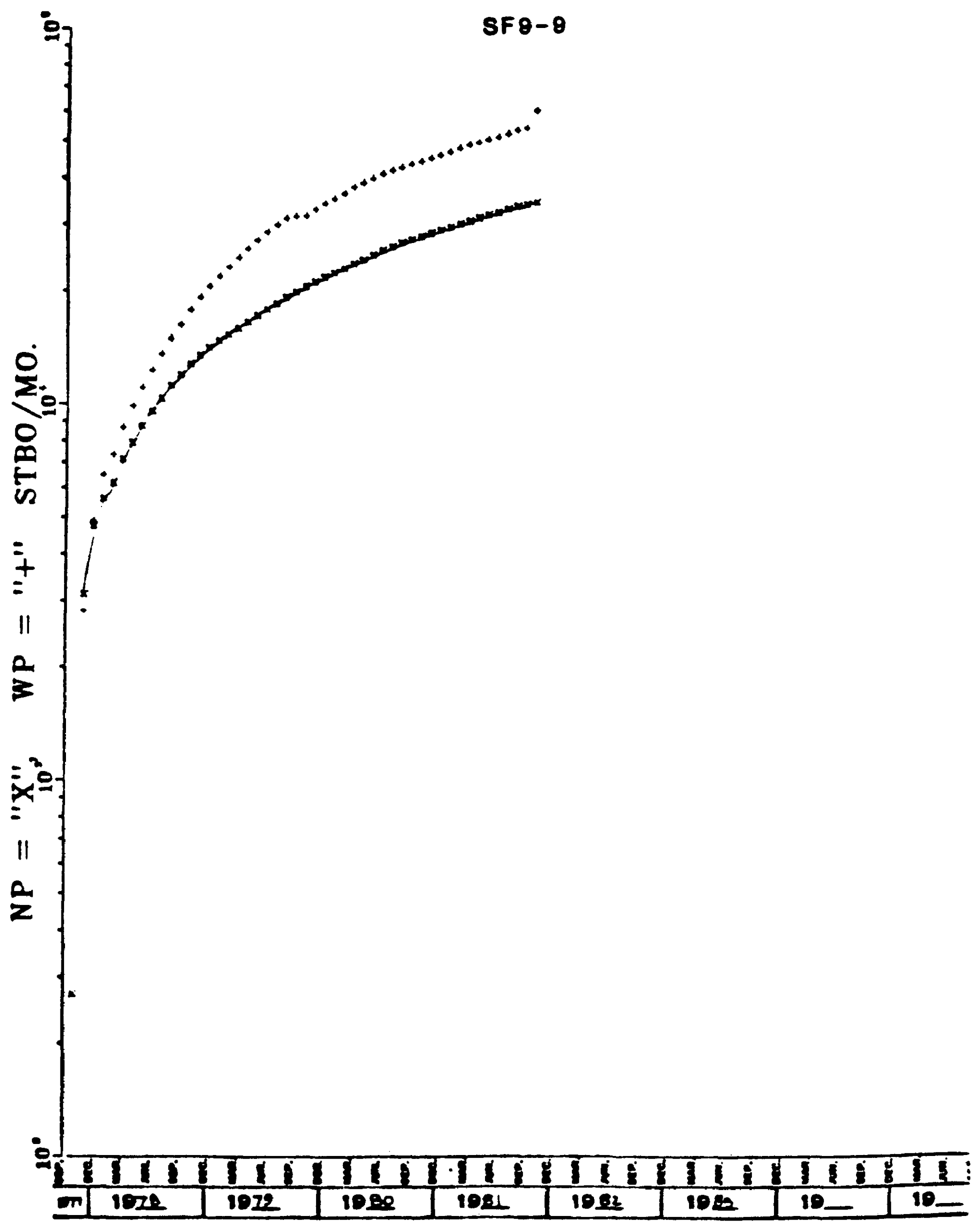
TIME VS. WATER CUT

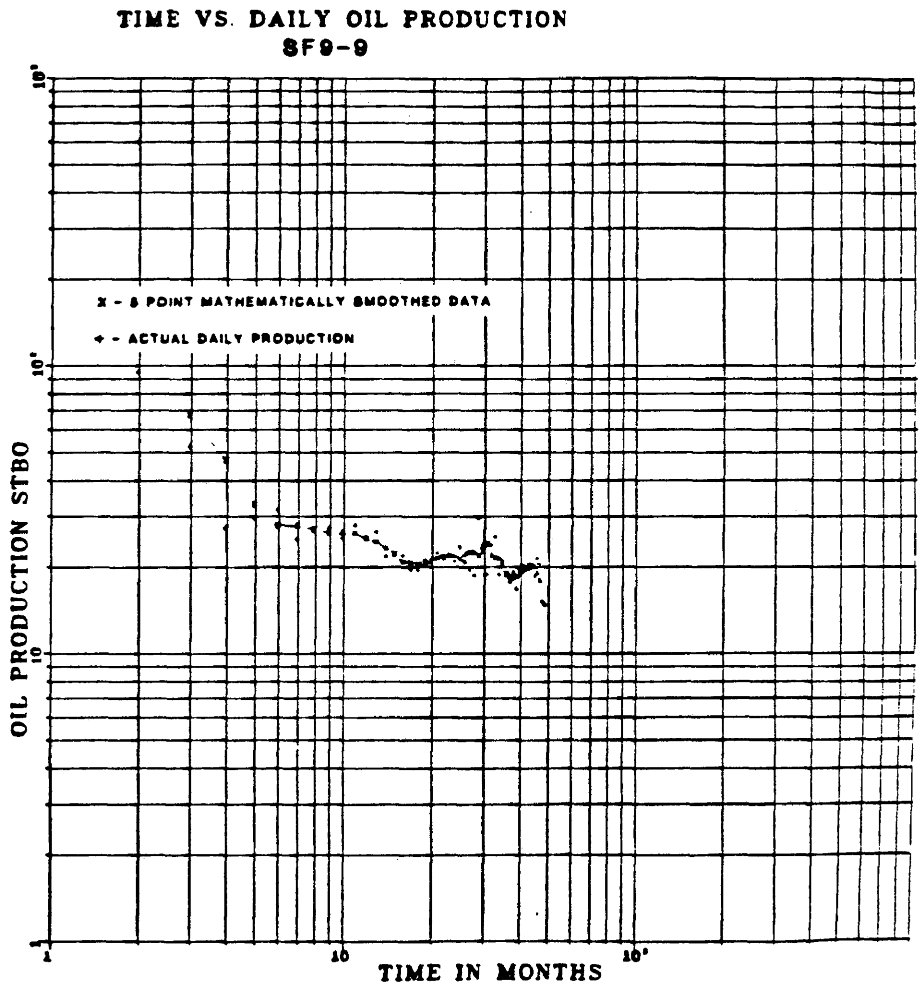


CUM. OIL PROD. VS. DAILY OIL PROD.

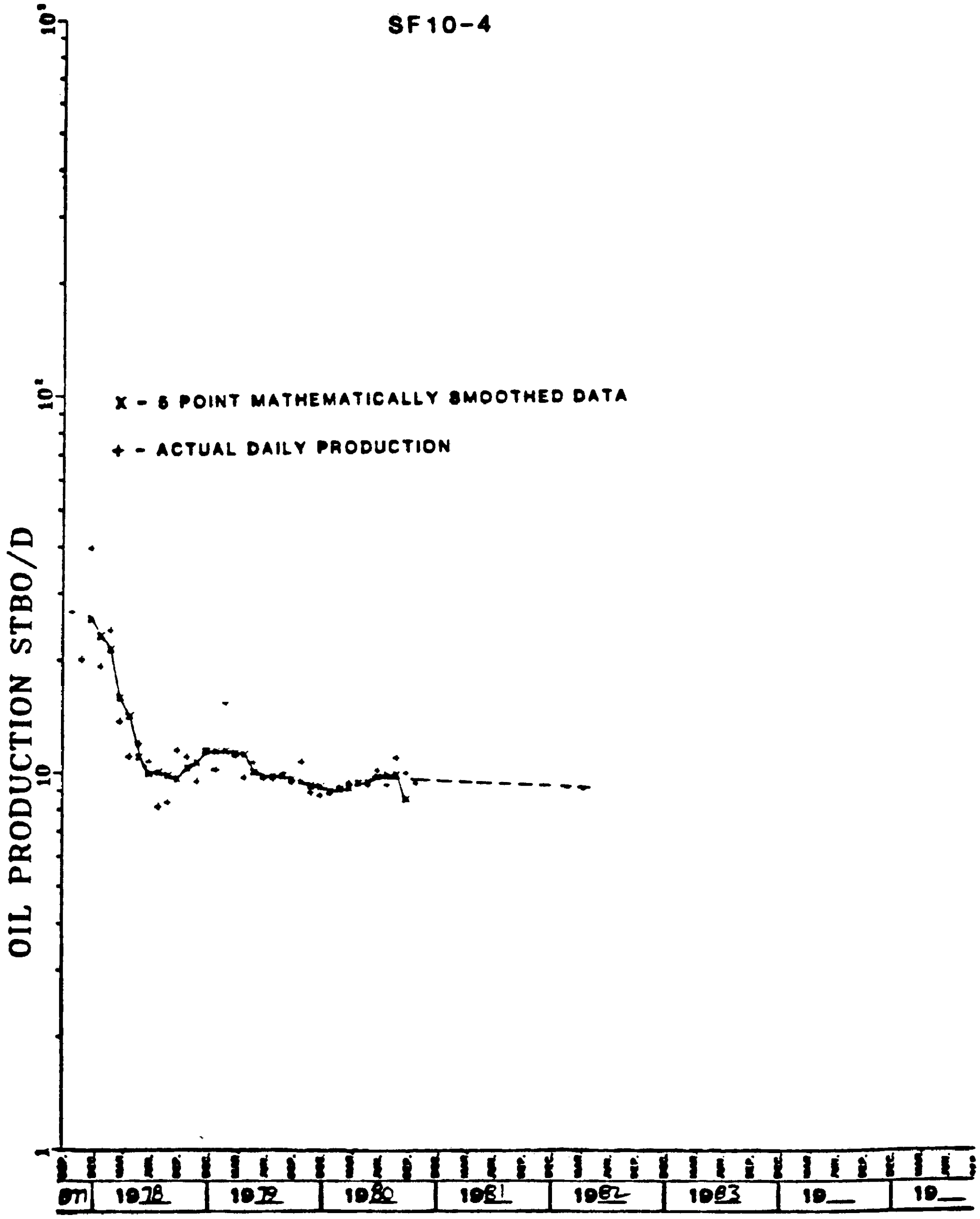


TIME VS. CUMM. OIL AND WATER PRODN.

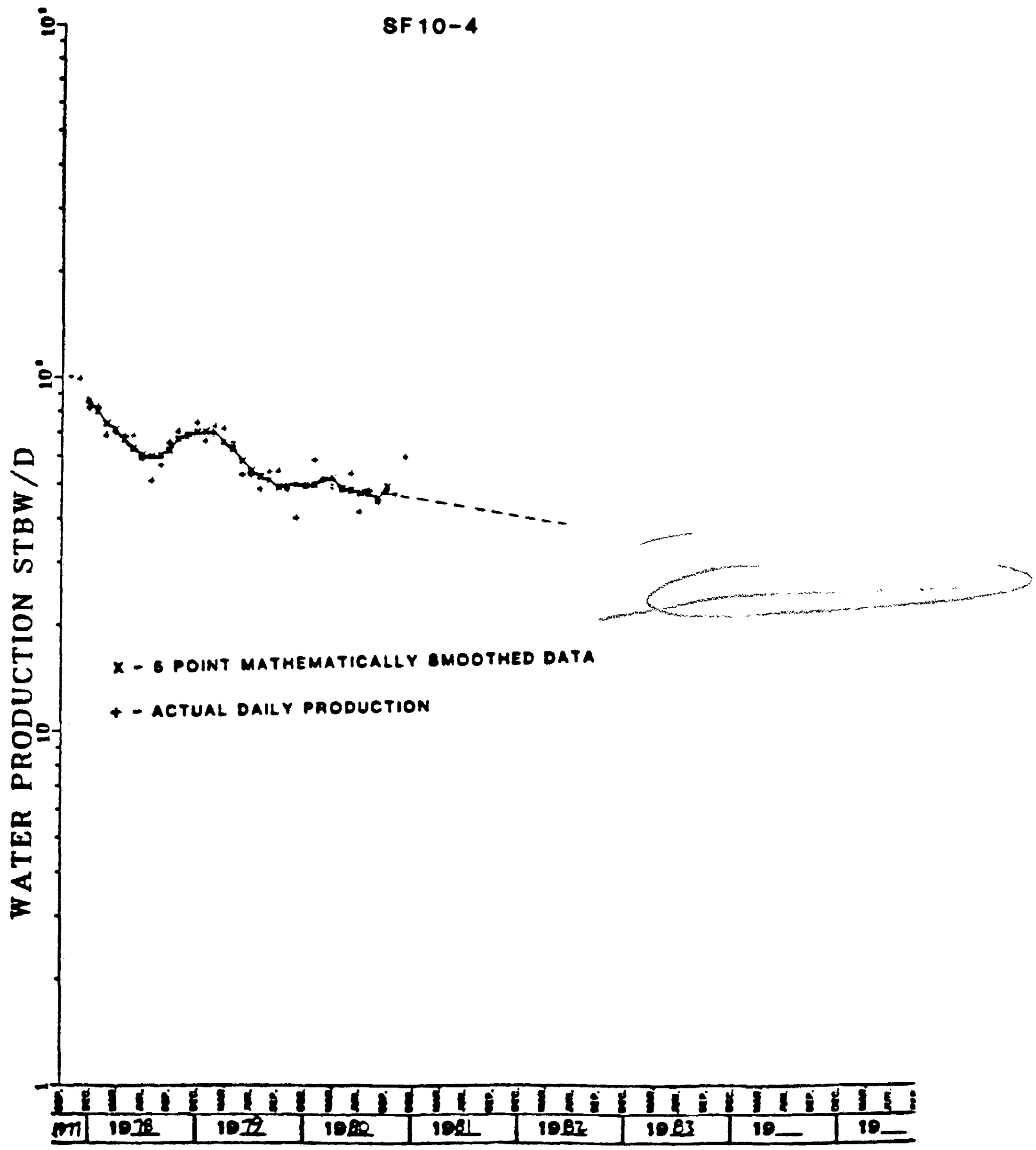



TIME VS. DAILY OIL PRODUCTION
SF9-9
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL PRODUCTION STBO
TIME IN MONTHS
1
10
10²
10³

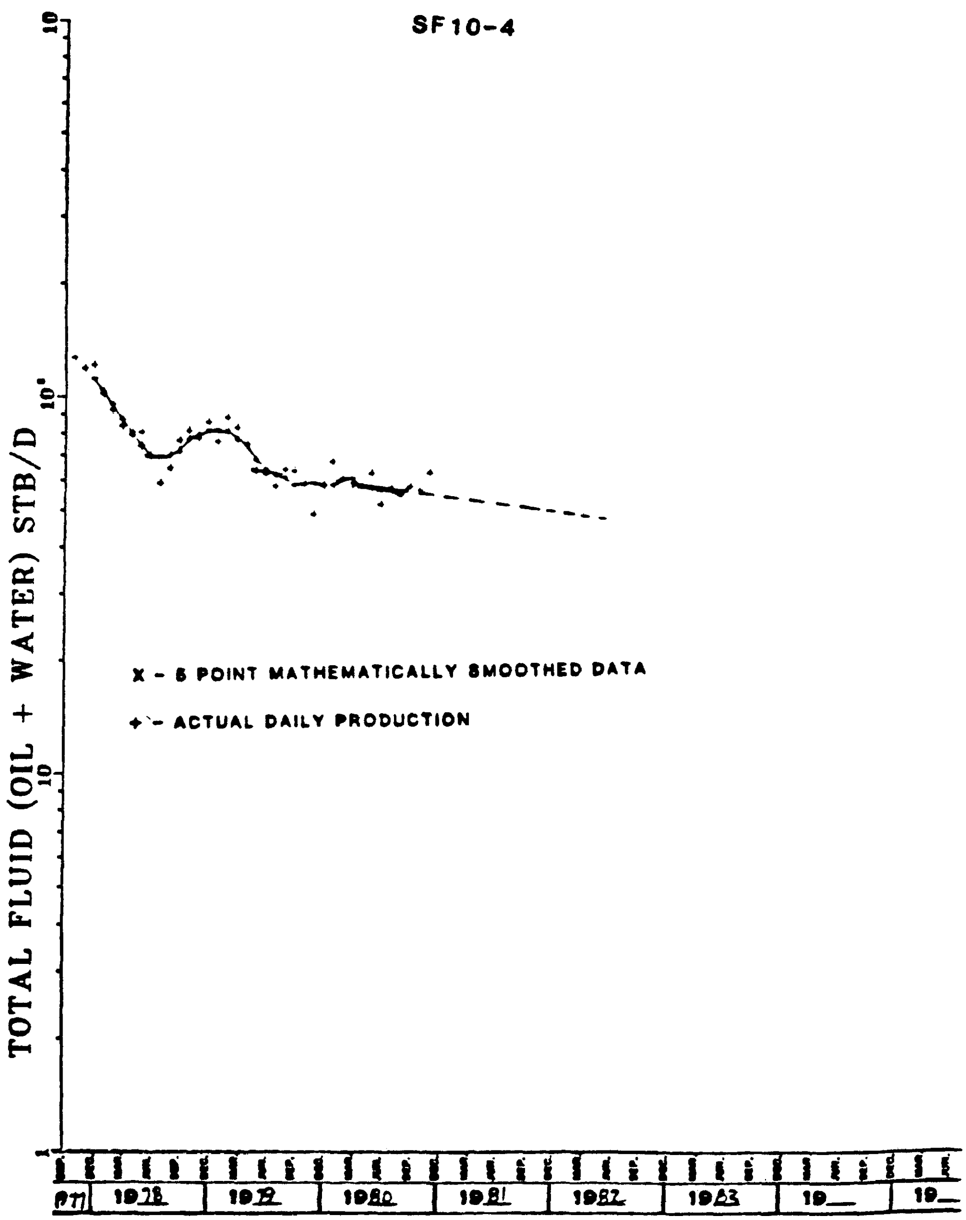
TIME VS. DAILY OIL PRODUCTION



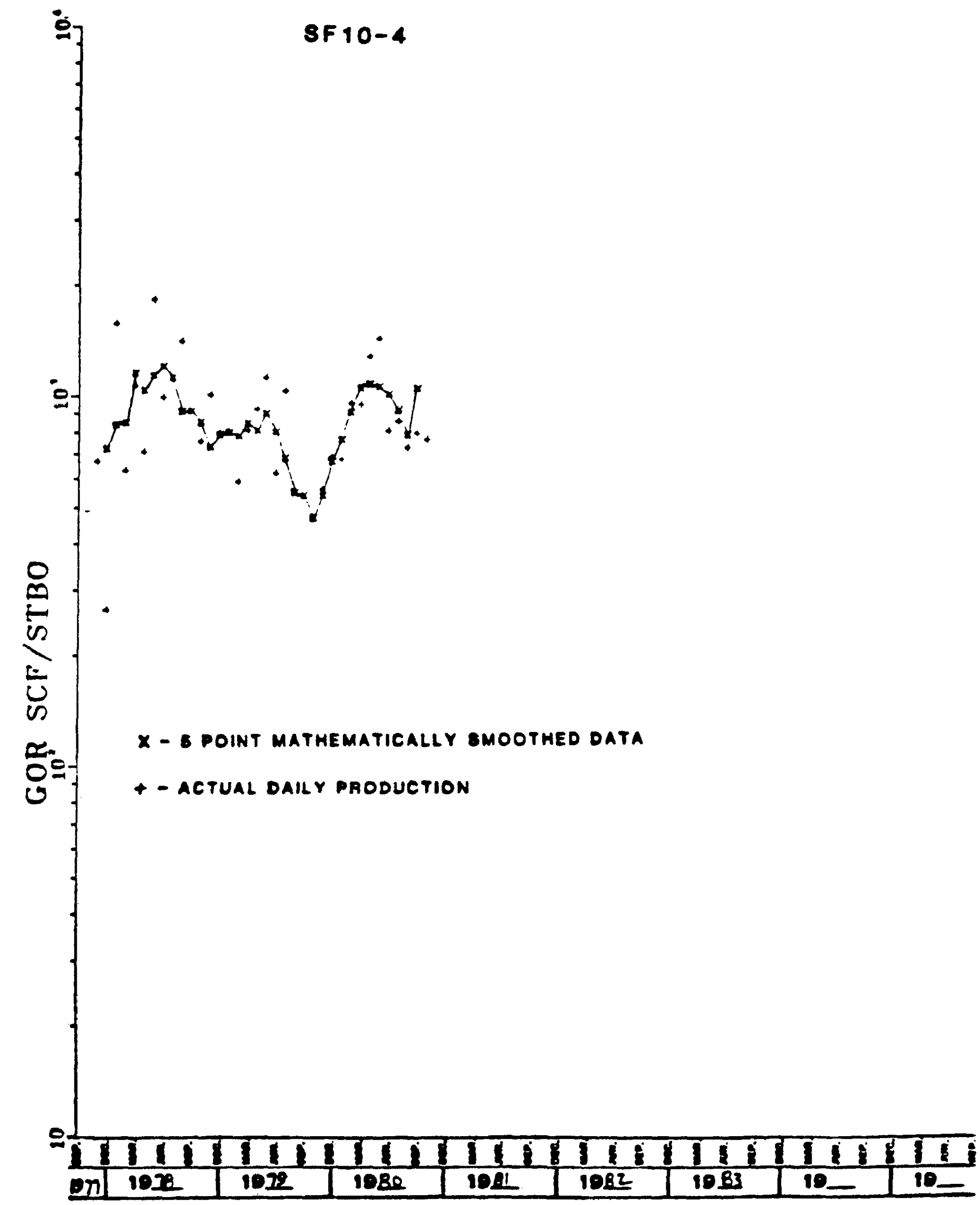
TIME VS. DAILY WATER PRODUCTION



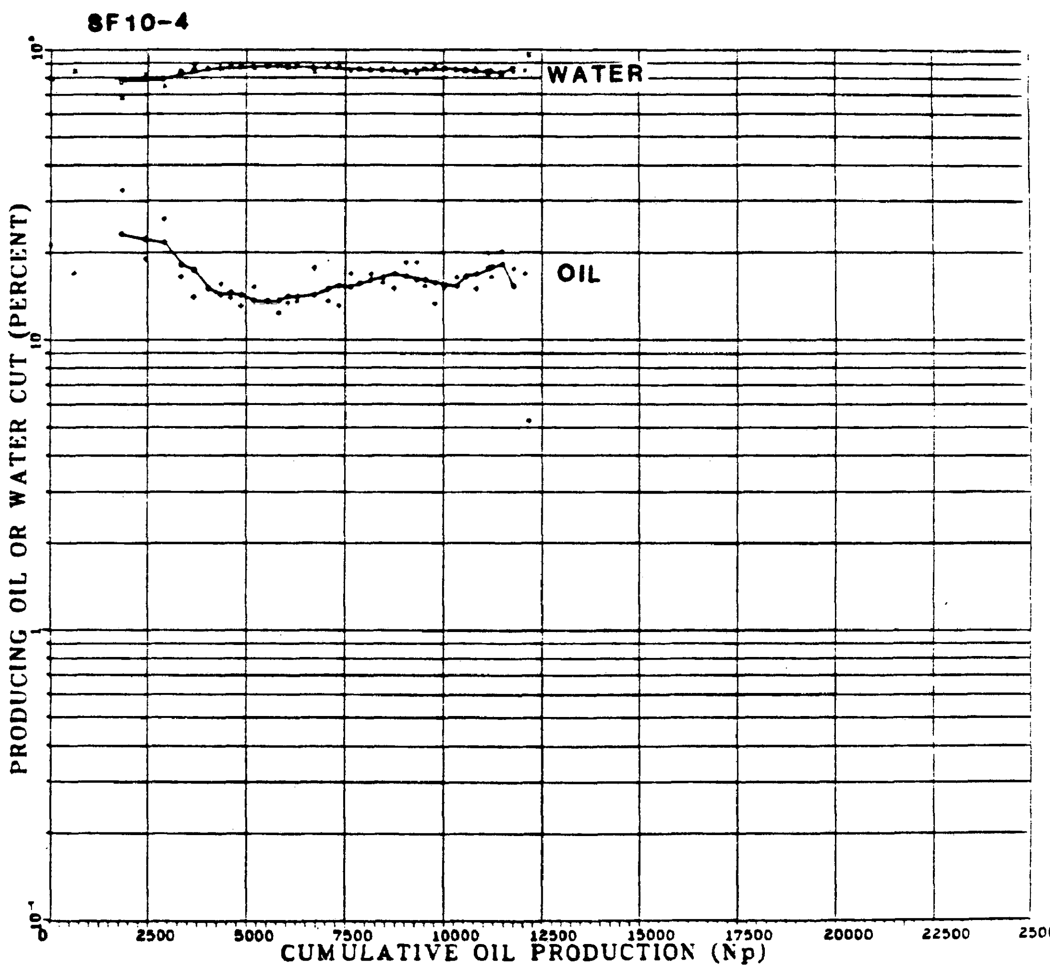
TIME VS. TOTAL FLUID PRODUCTION



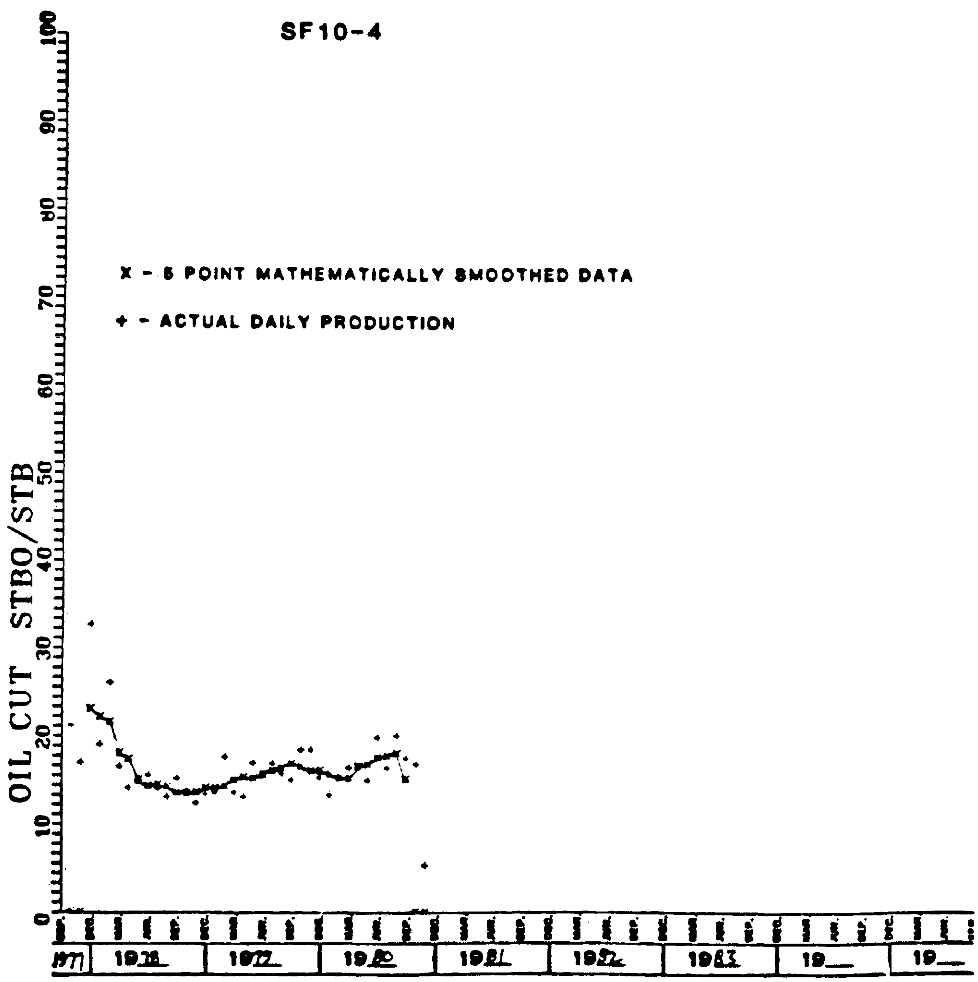
TIME VS. GAS OIL RATIO



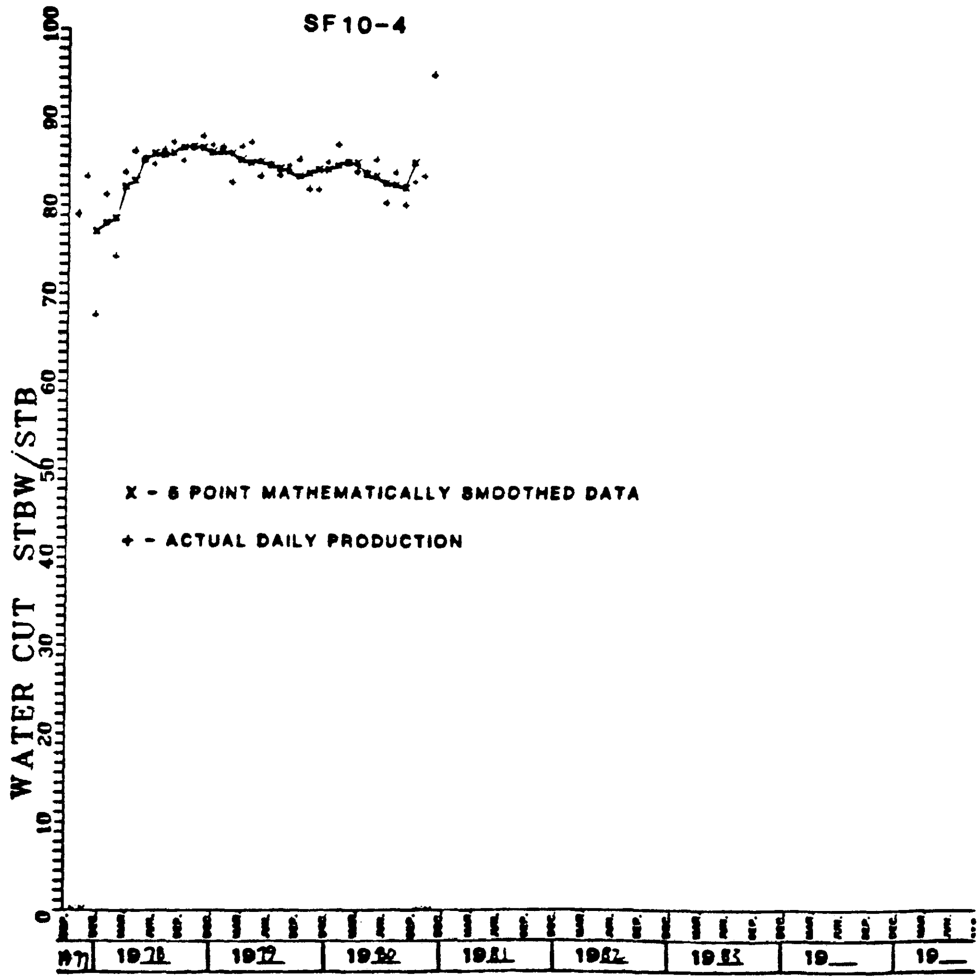
OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION



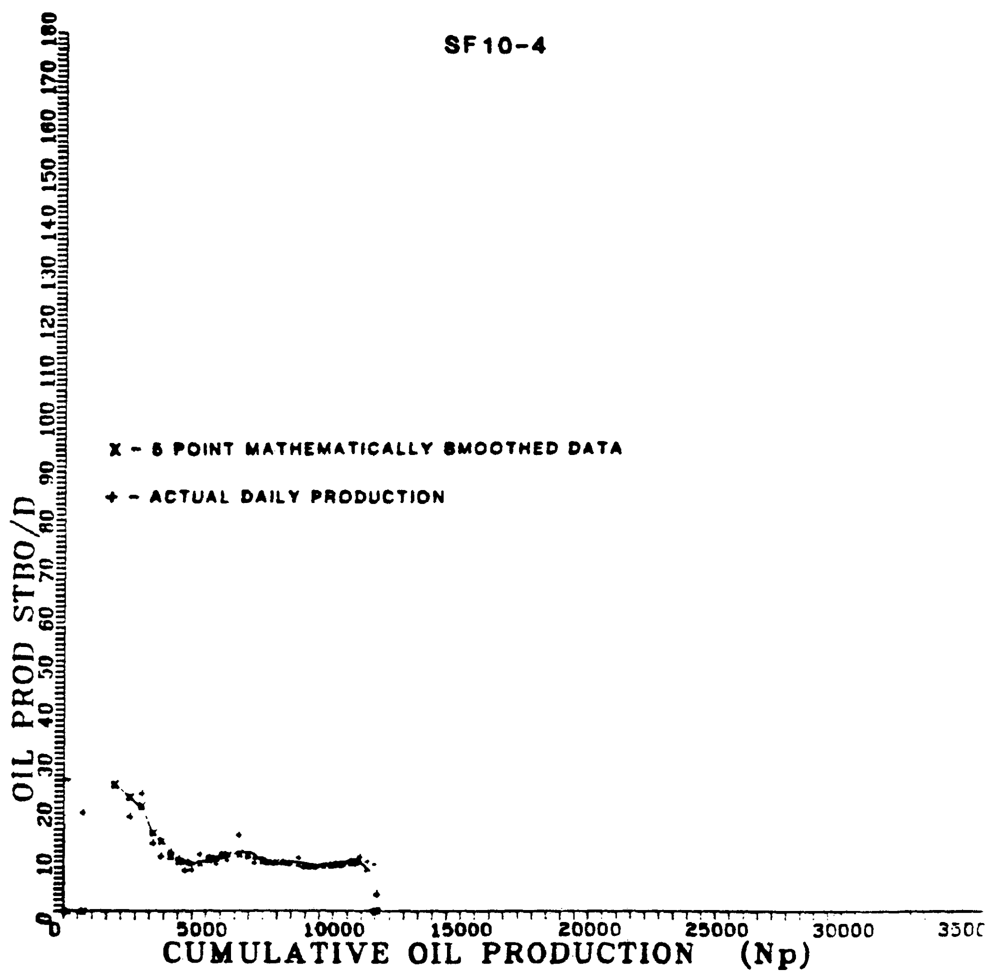
TIME VS. OIL CUT



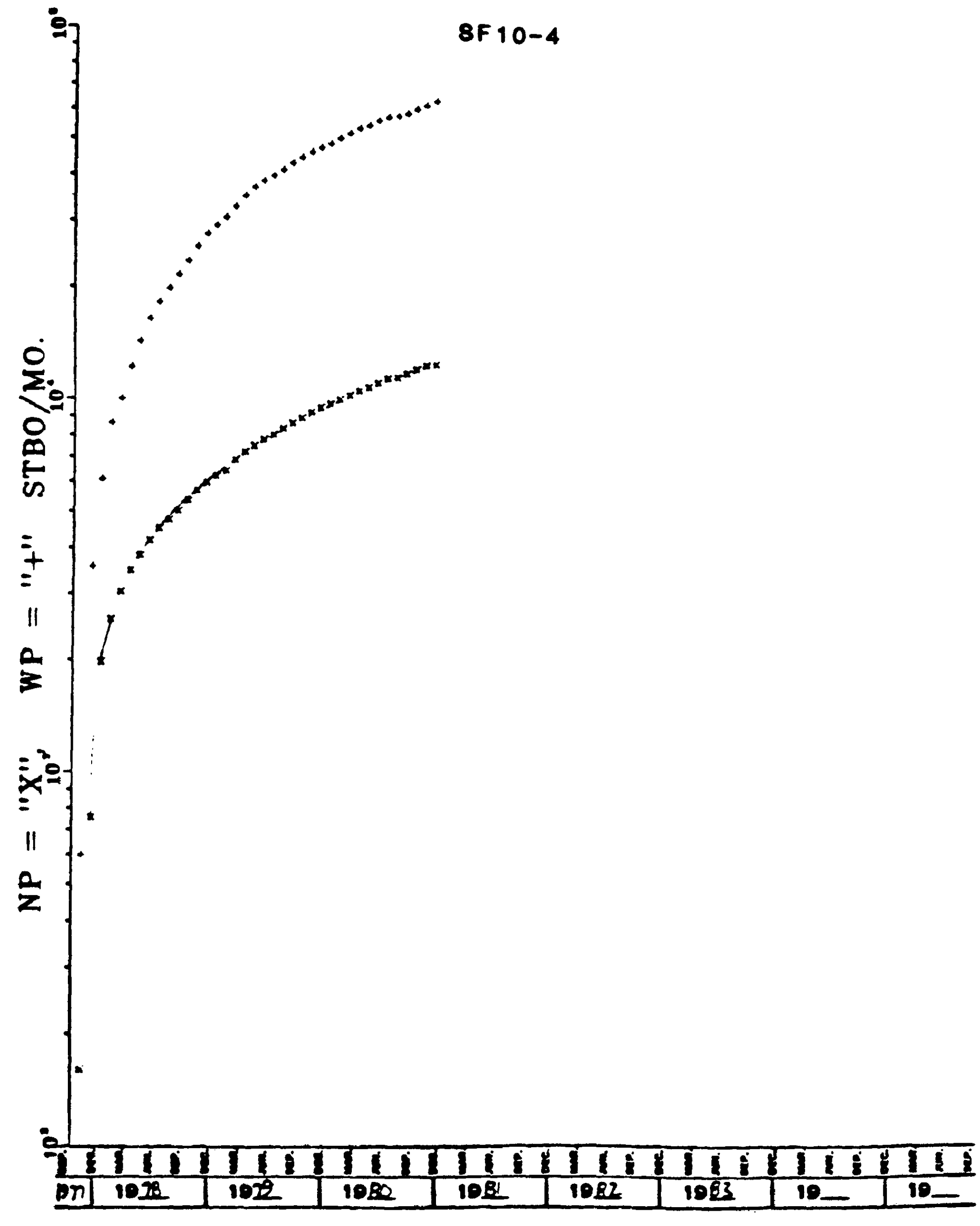
TIME VS. WATER CUT



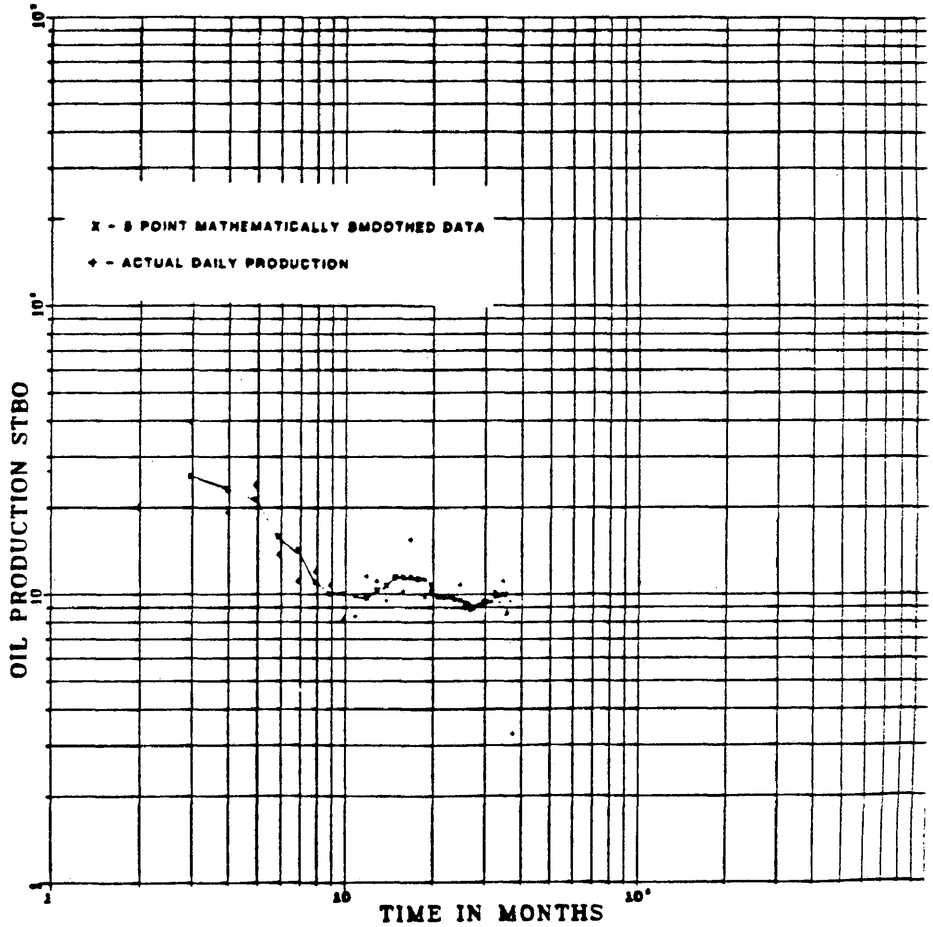
CUM. OIL PROD. VS. DAILY OIL PROD.



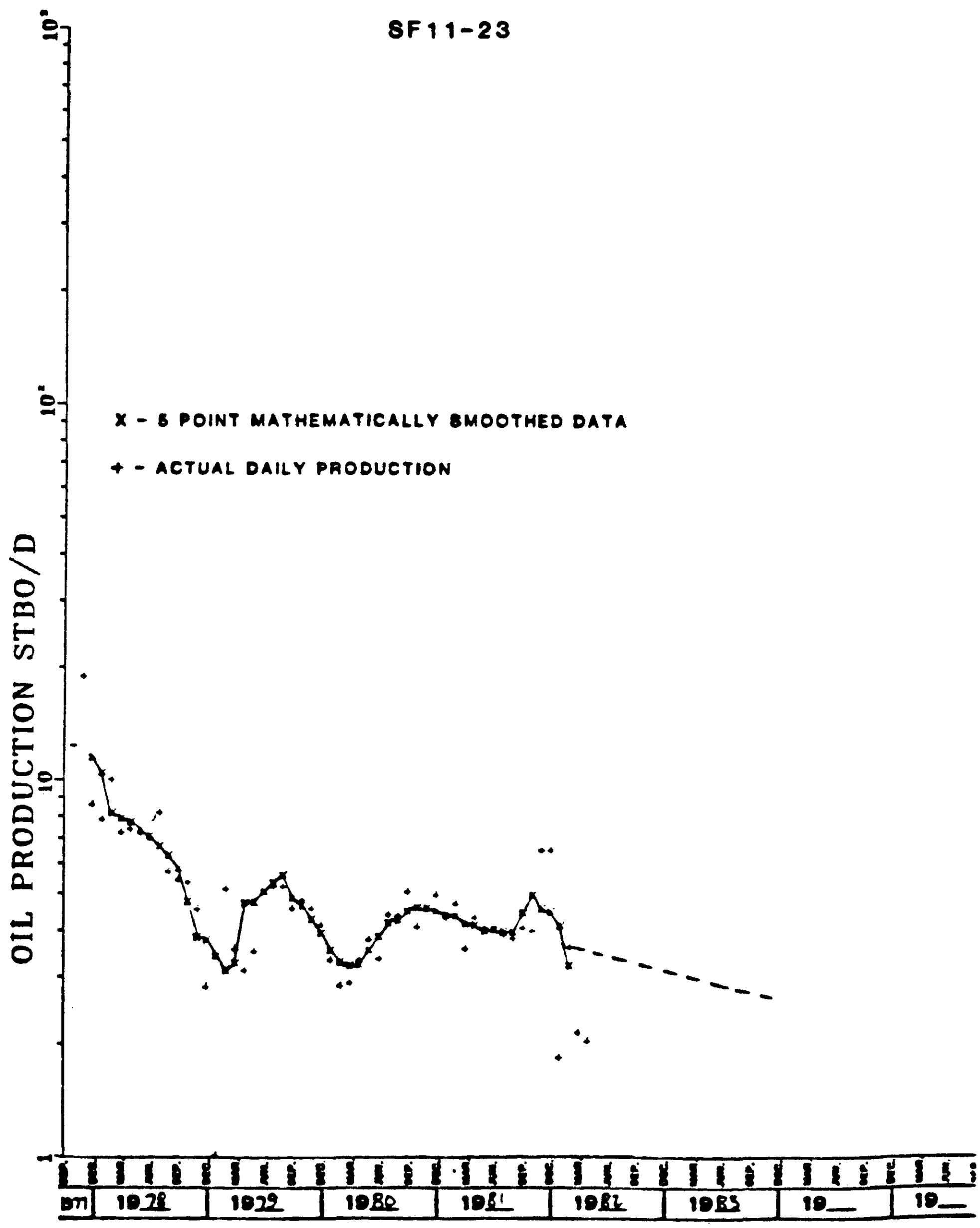
TIME VS. CUM. OIL AND WATER PRODN.



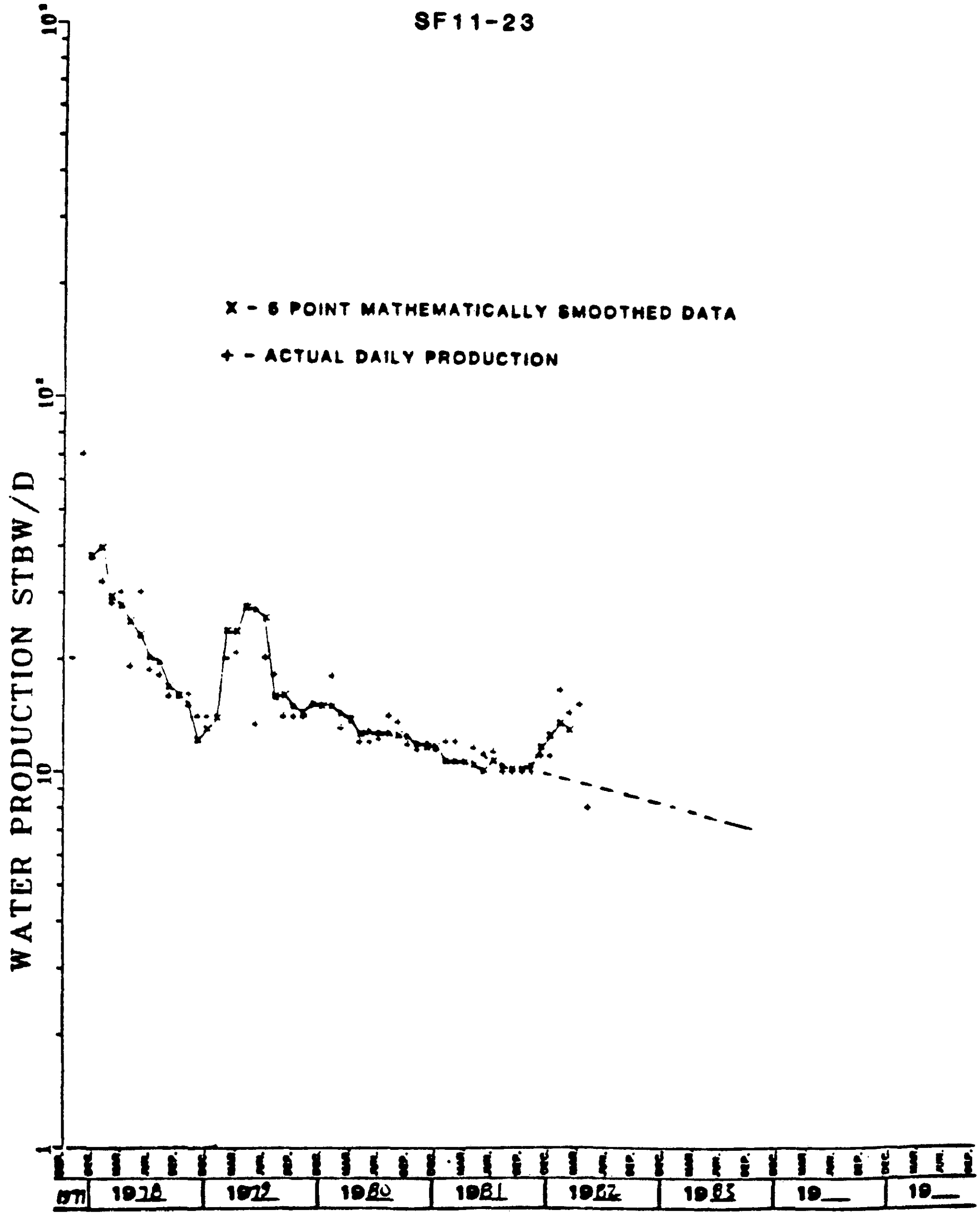
TIME VS. DAILY OIL PRODUCTION
SF 10-4



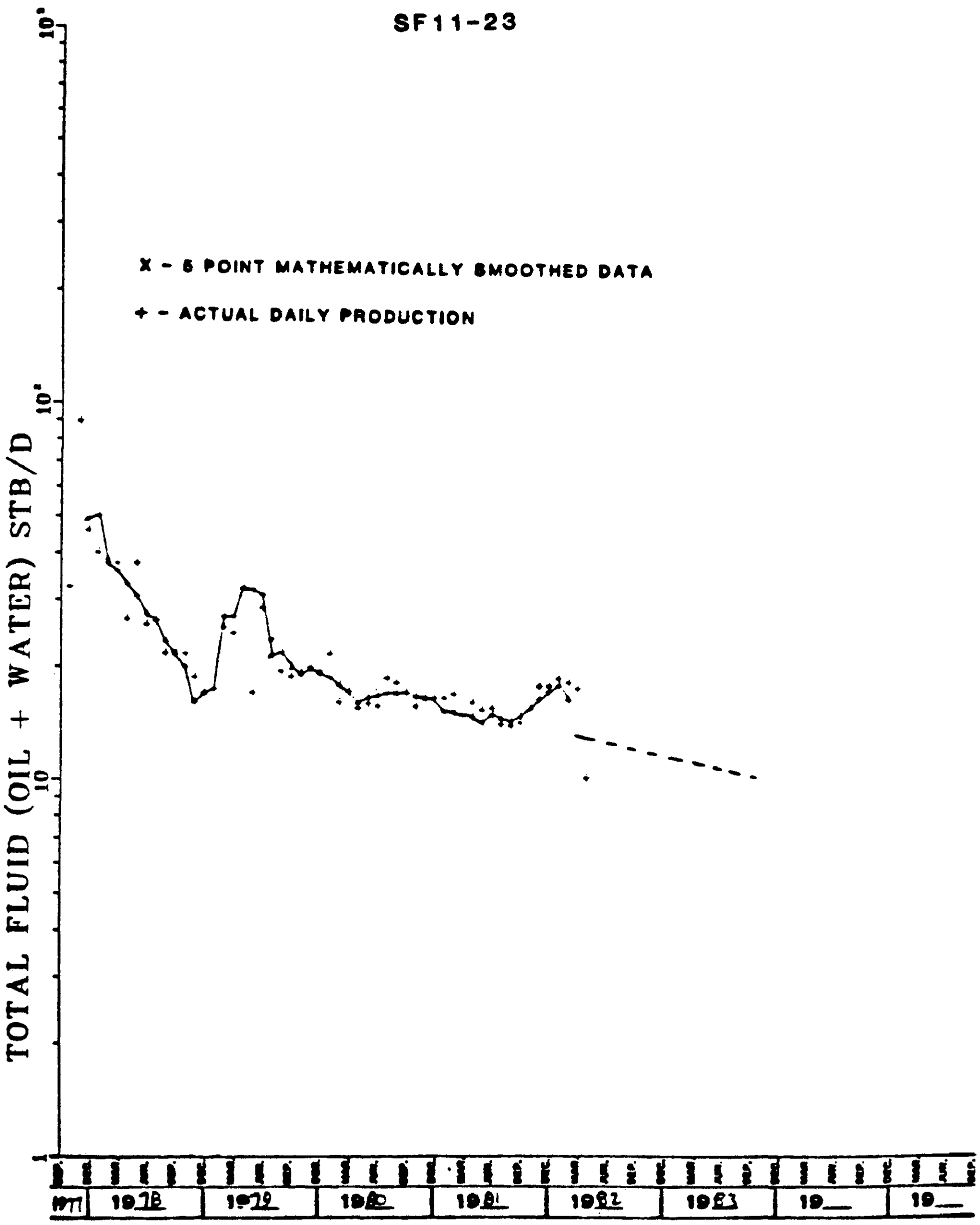
TIME VS. DAILY OIL PRODUCTION



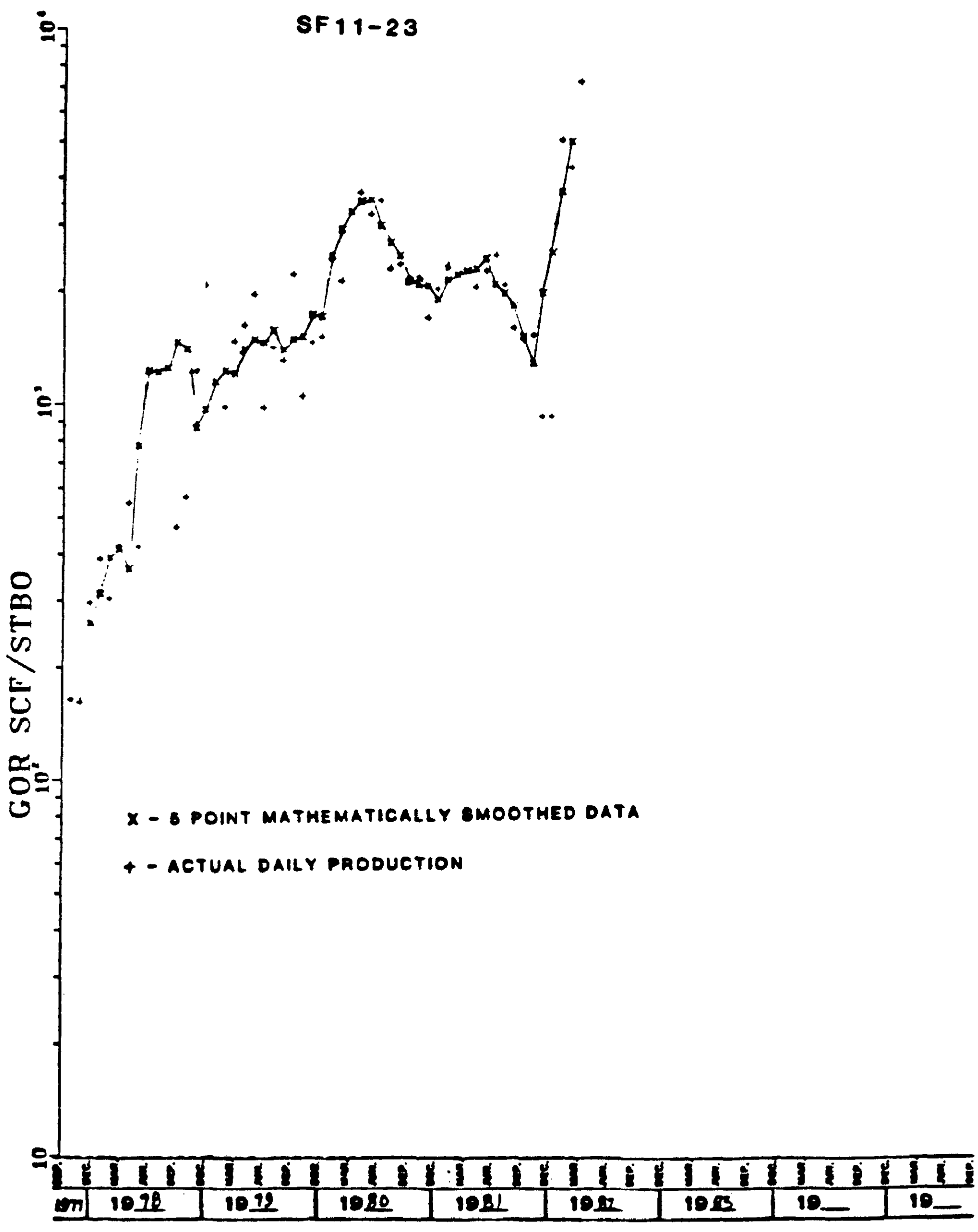
TIME VS. DAILY WATER PRODUCTION



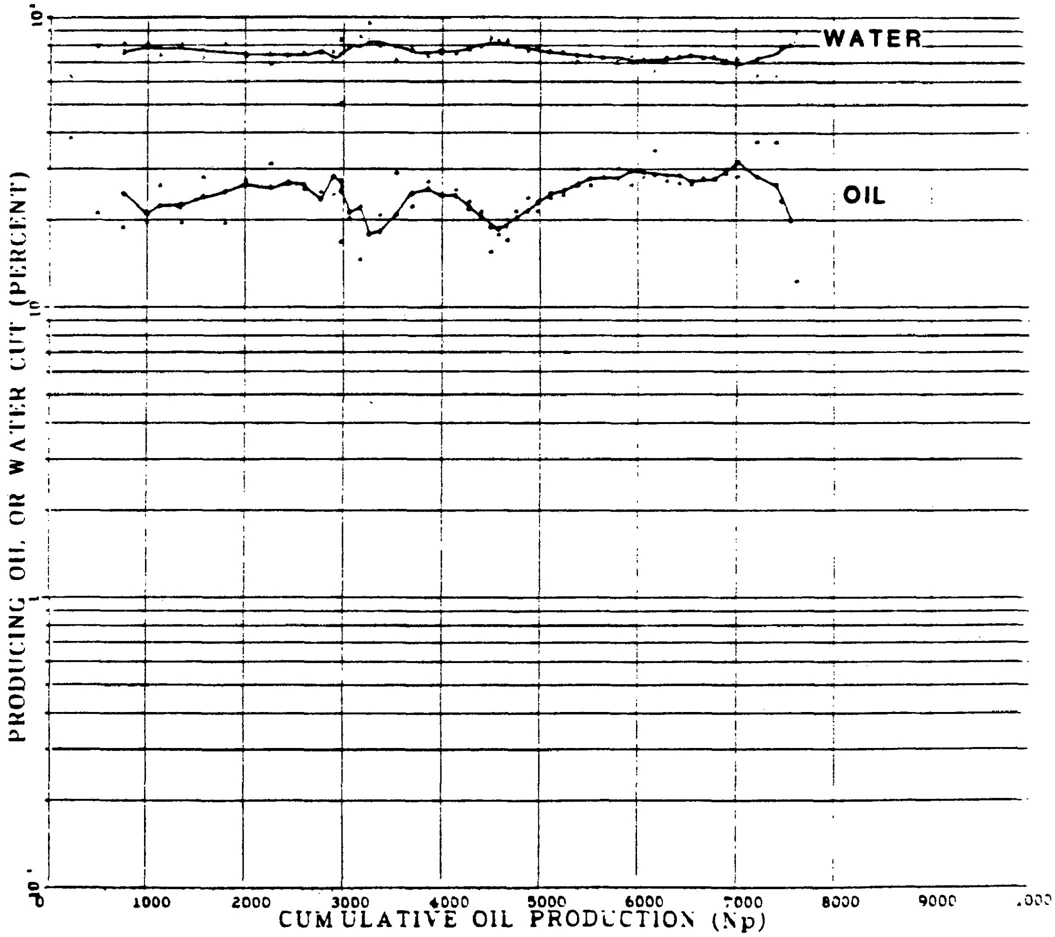
TIME VS. TOTAL FLUID PRODUCTION



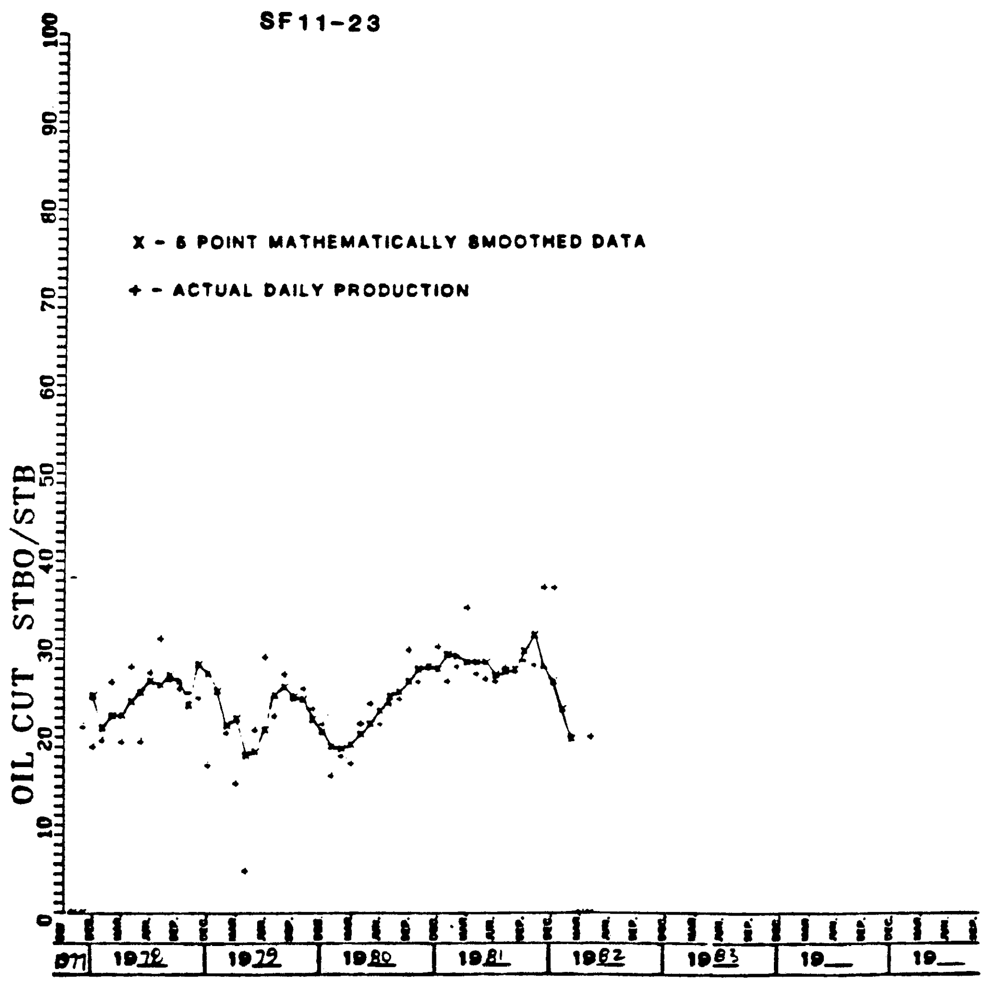
TIME VS. GAS OIL RATIO



OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION
SF11-23

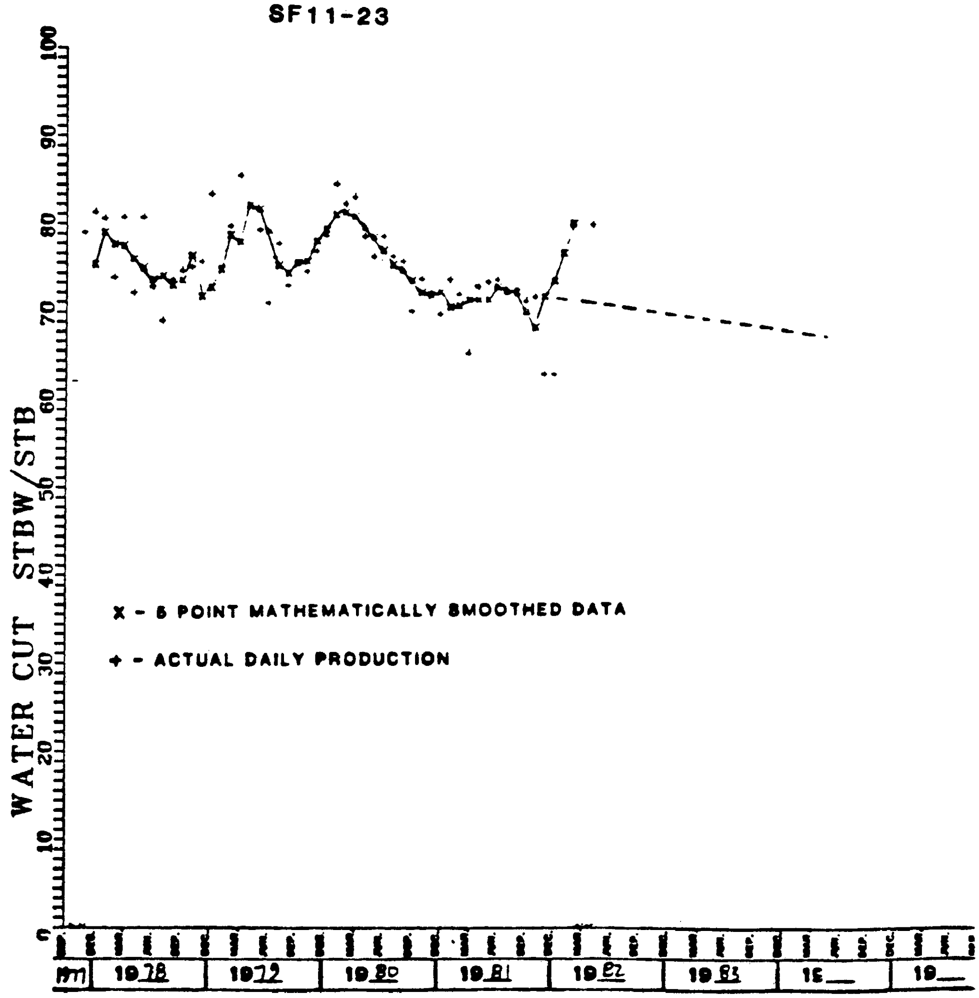


TIME VS. OIL CUT

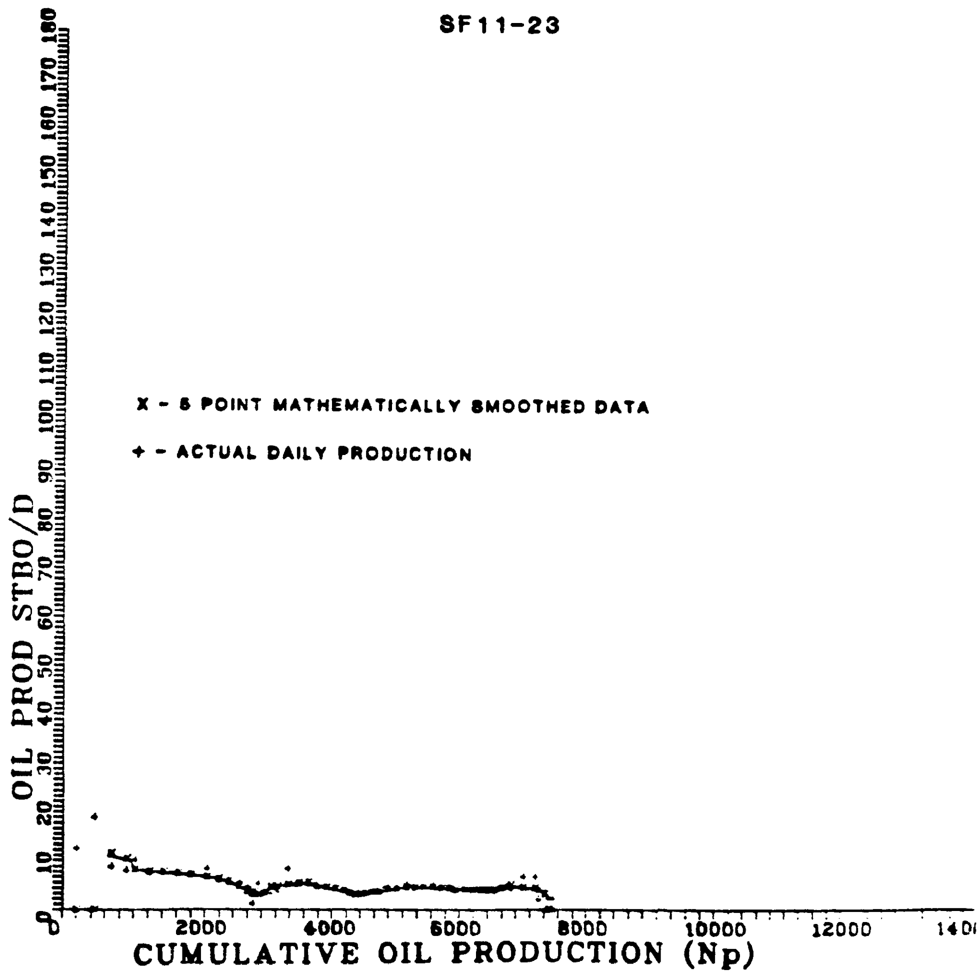


TIME VS. WATER CUT

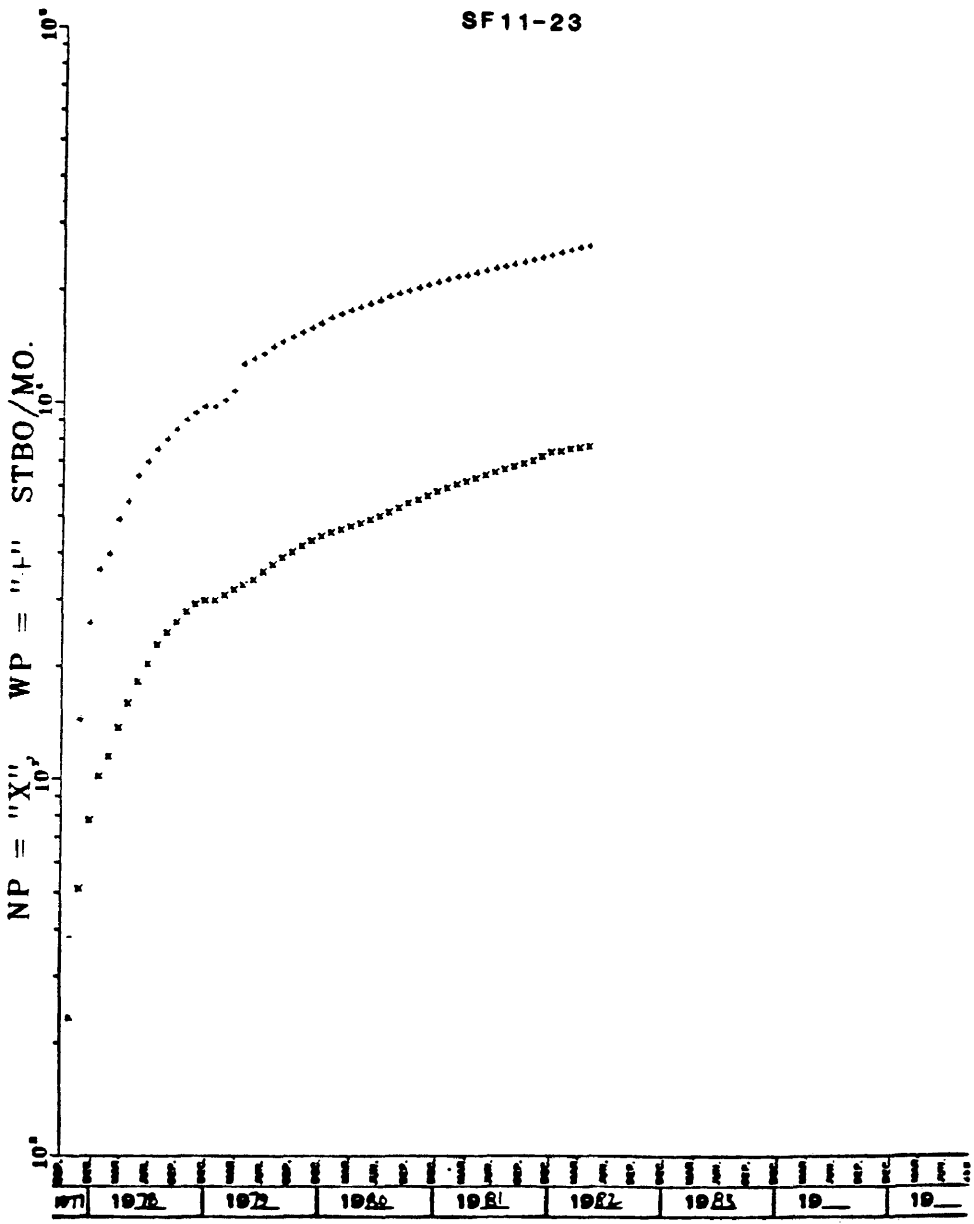
SF11-23



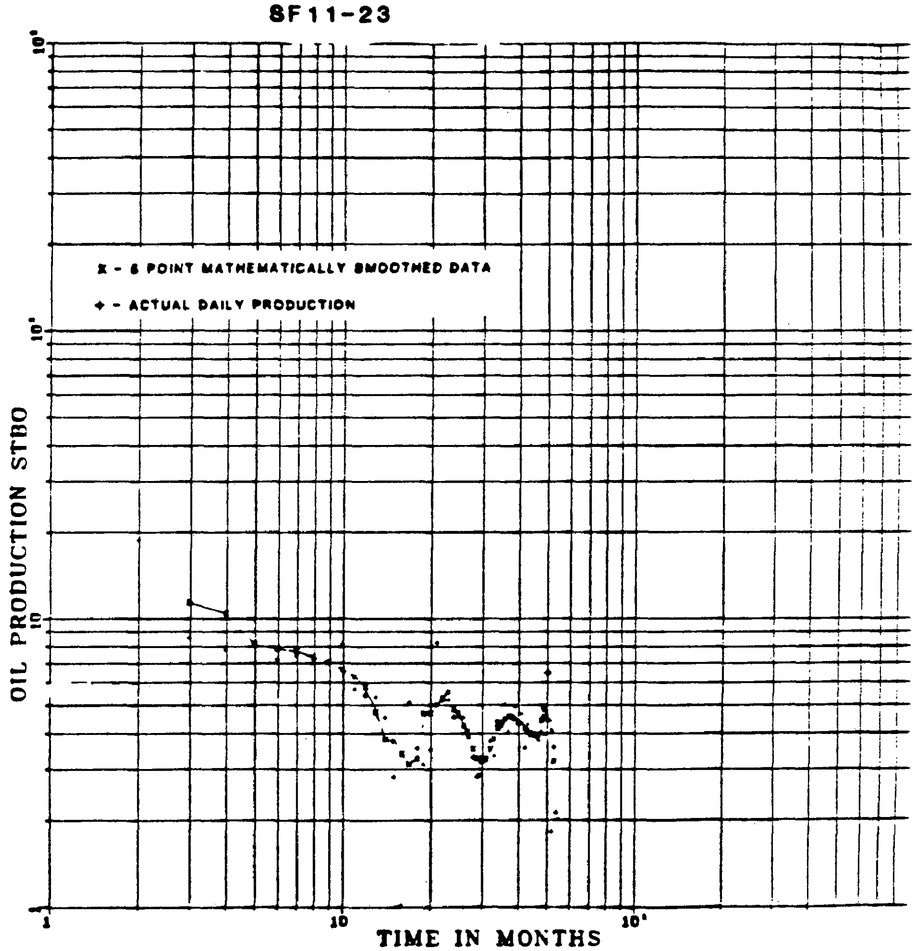
CUM. OIL PROD. VS. DAILY OIL PROD.



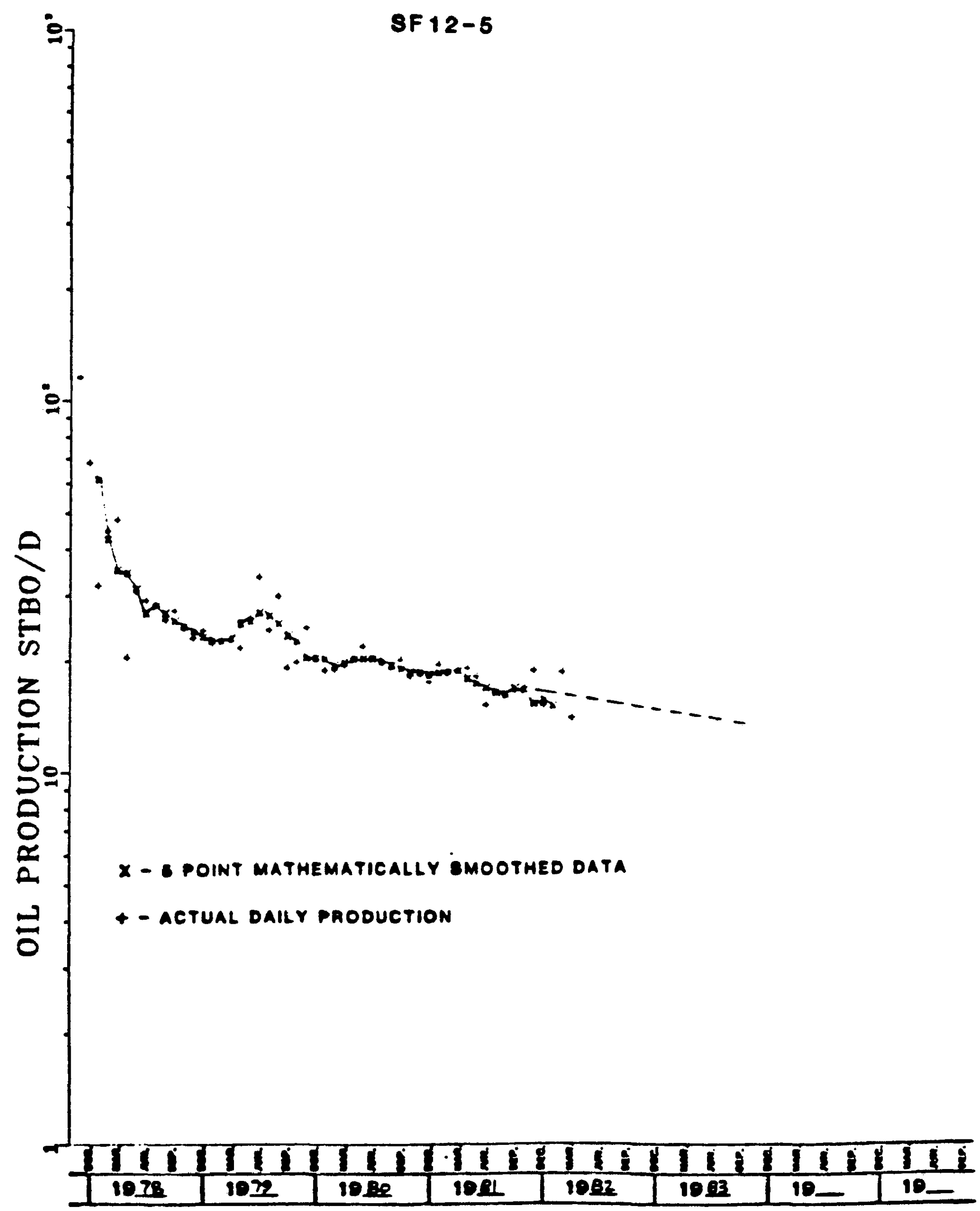
TIME VS. CUM. OIL AND WATER PRODN.



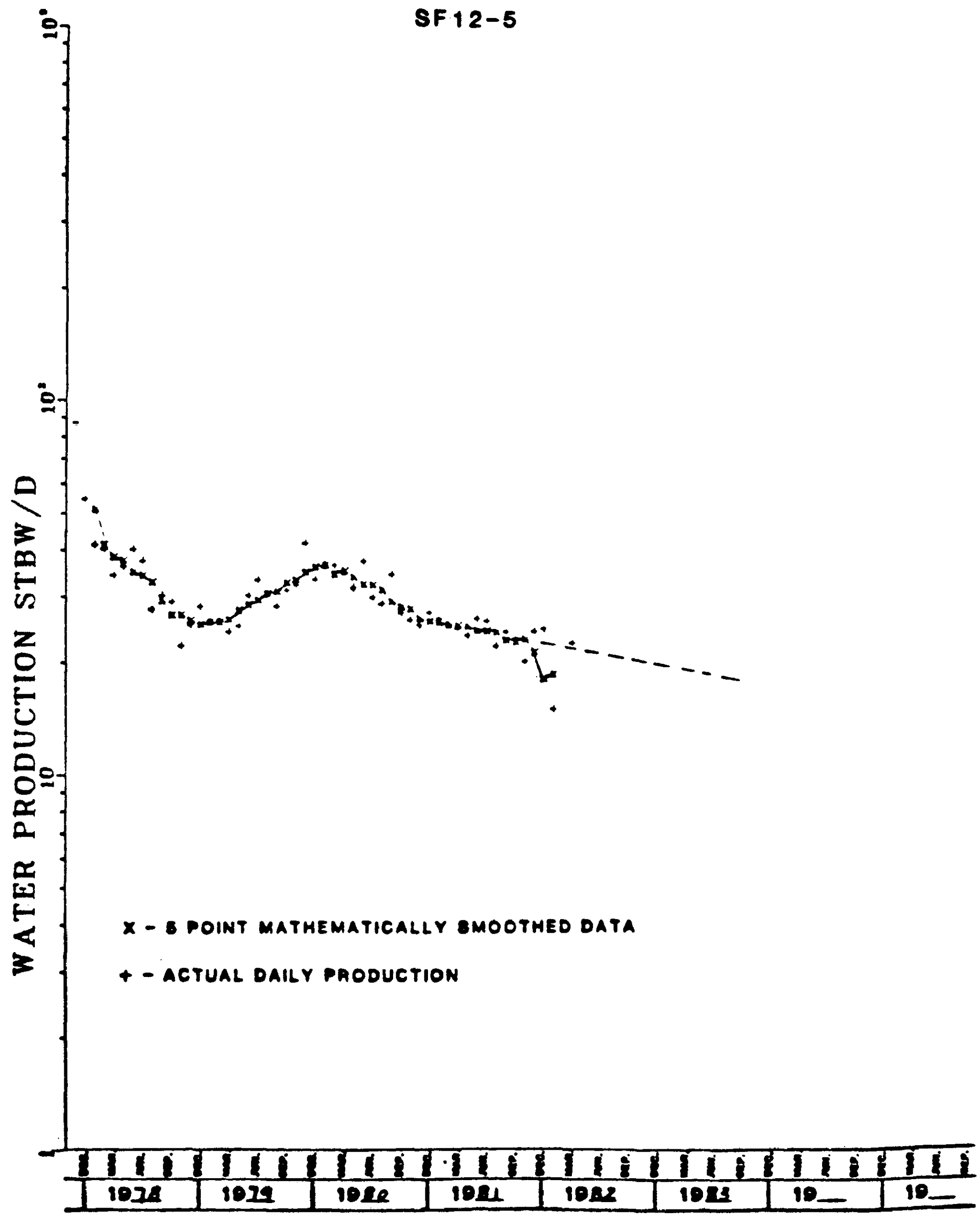
TIME VS. DAILY OIL PRODUCTION
SF11-23



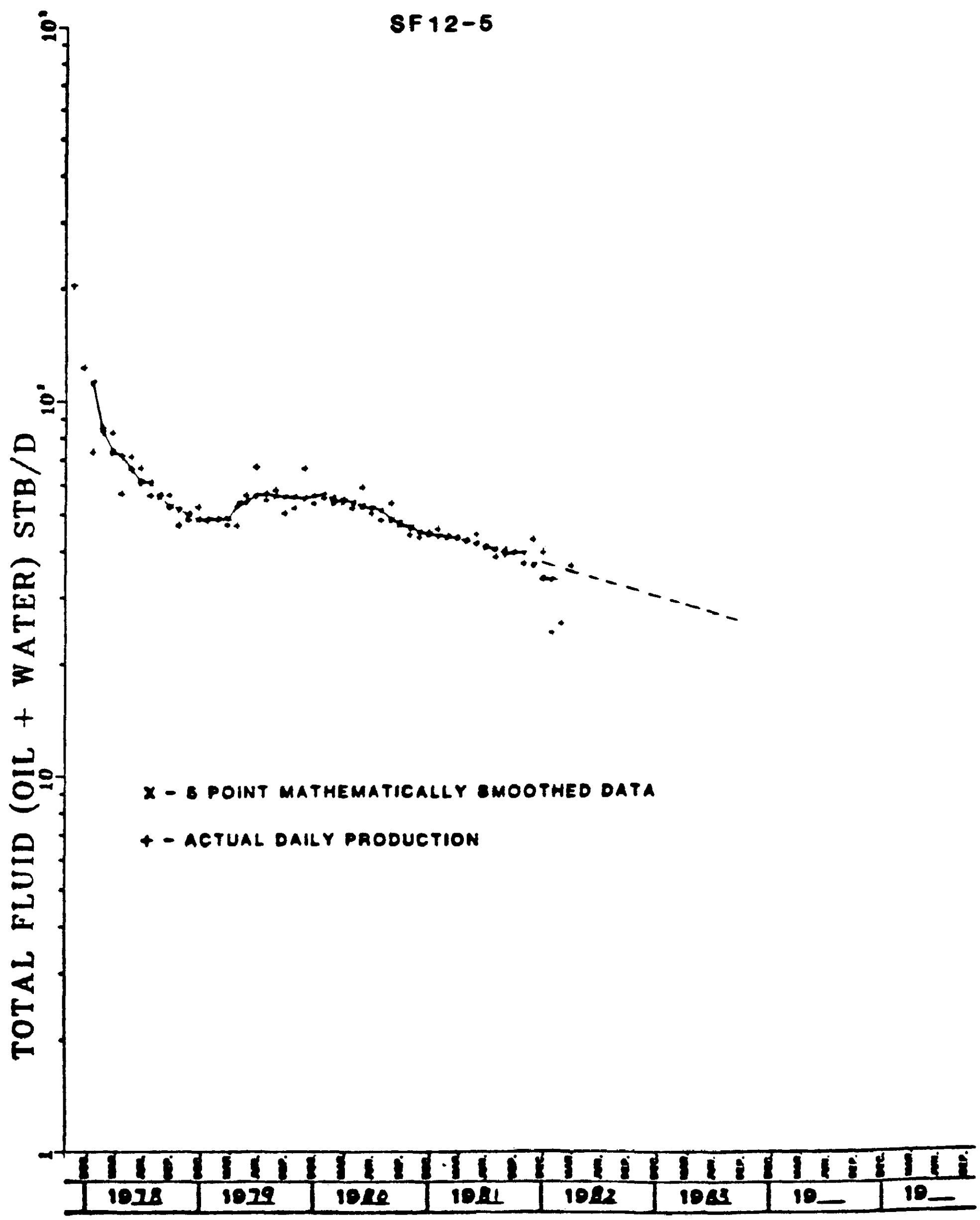
TIME VS. DAILY OIL PRODUCTION



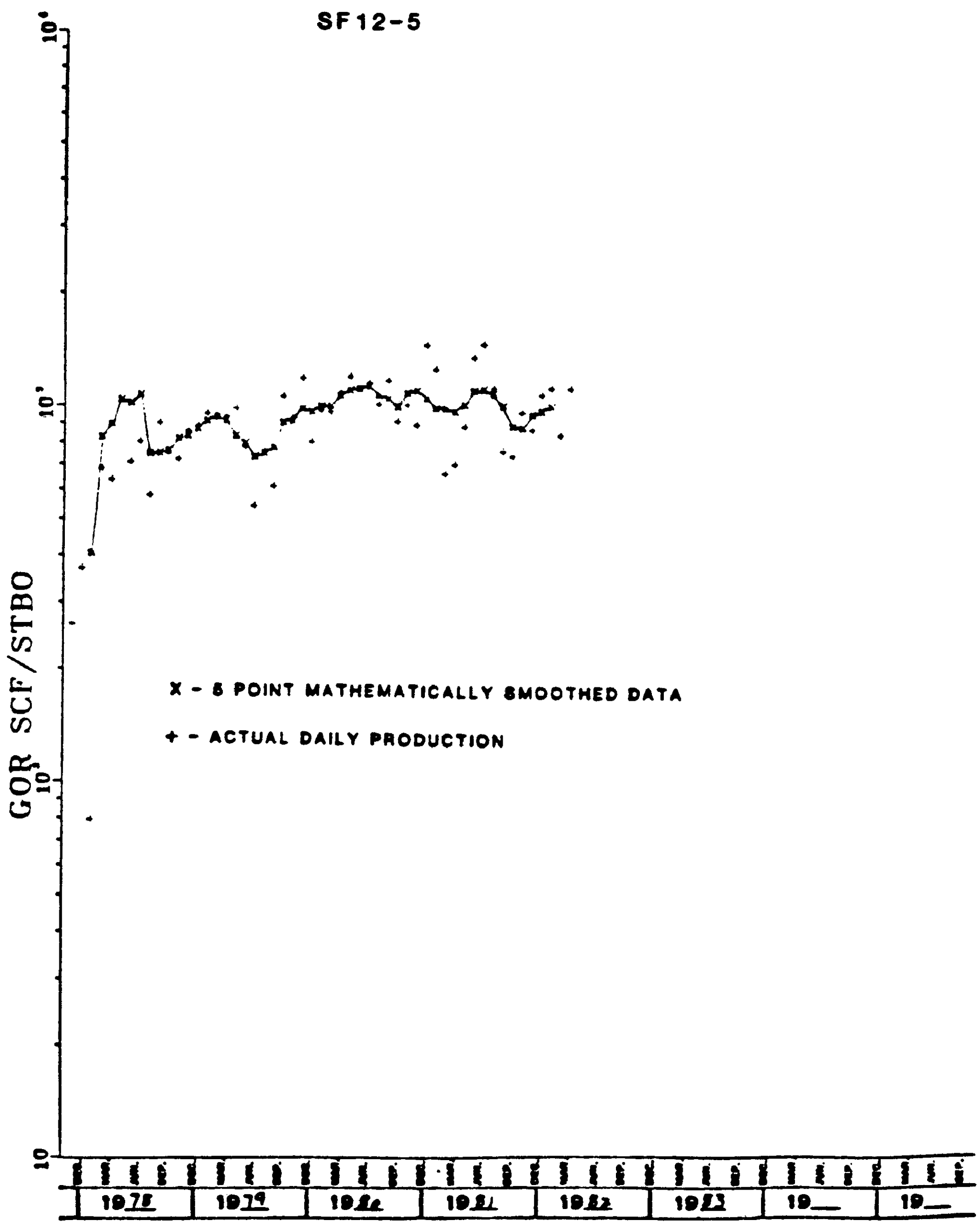
TIME VS. DAILY WATER PRODUCTION



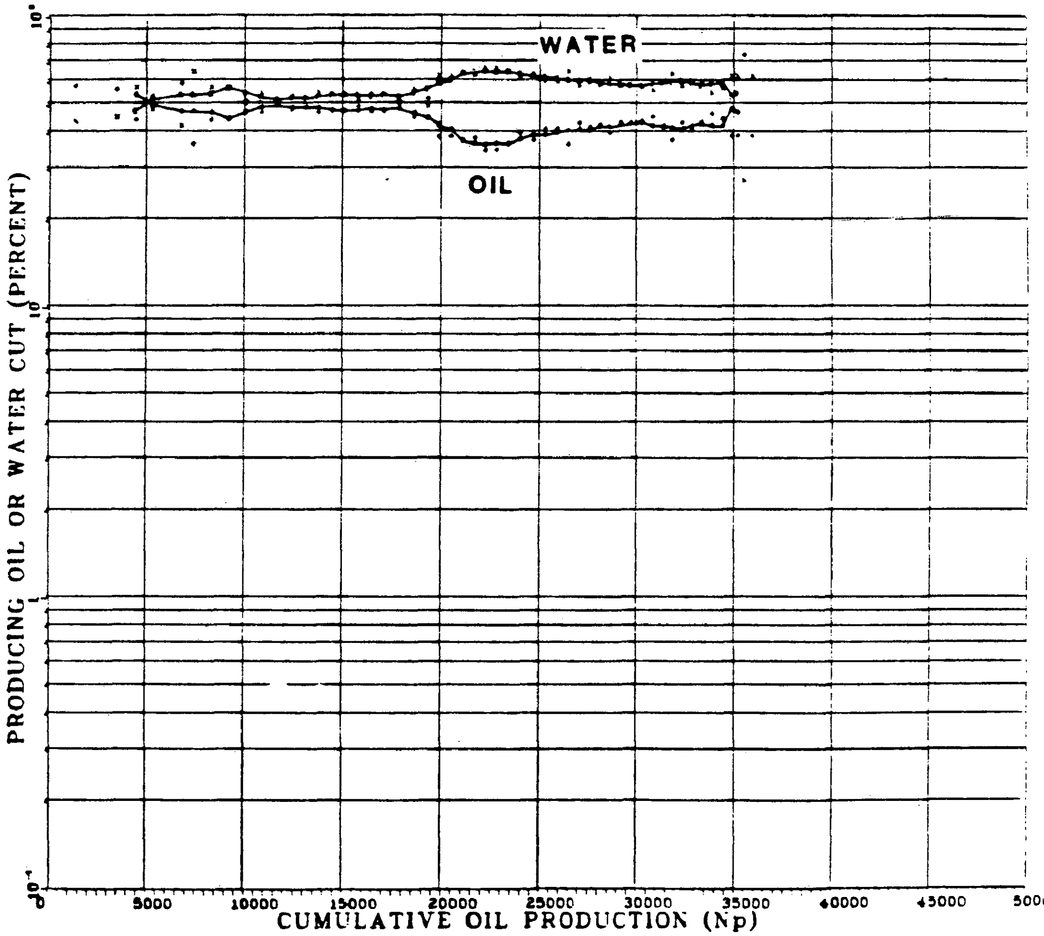
TIME VS. TOTAL FLUID PRODUCTION

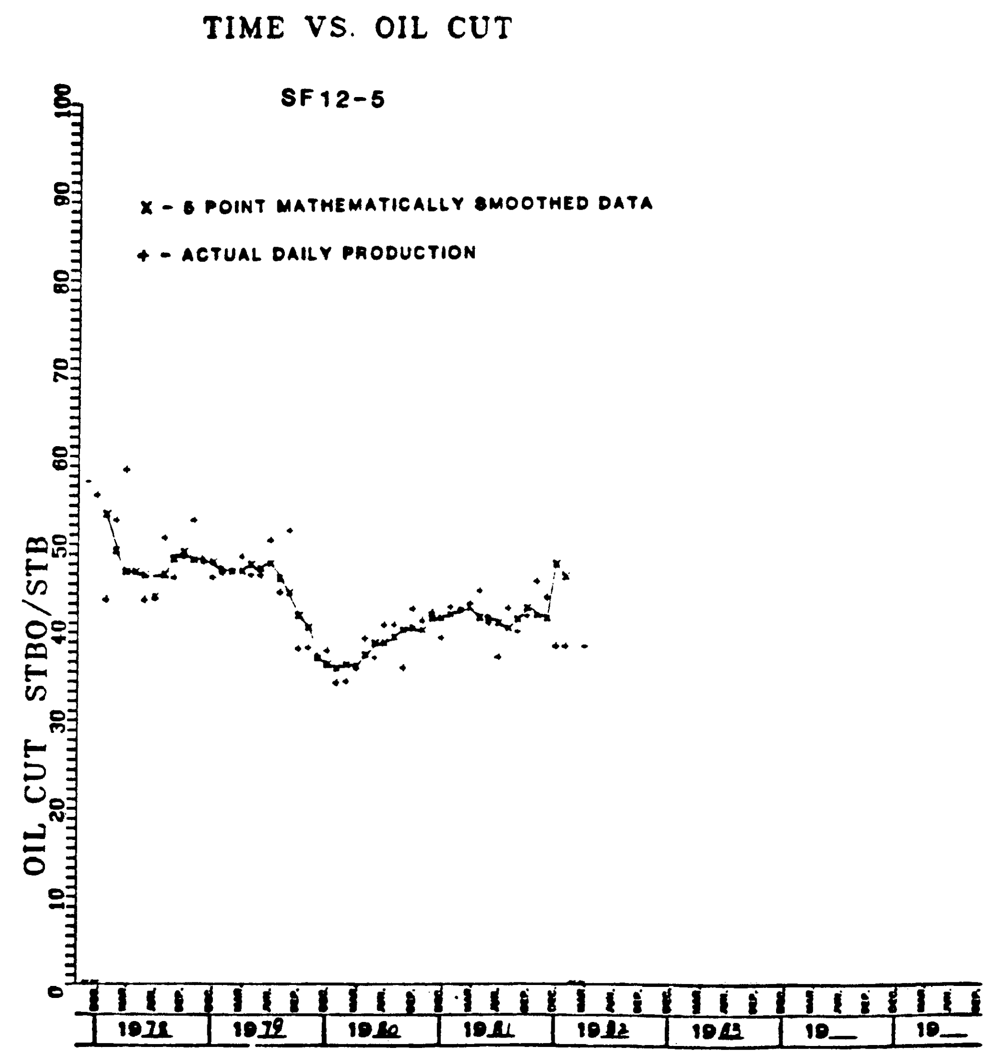


TIME VS. GAS OIL RATIO

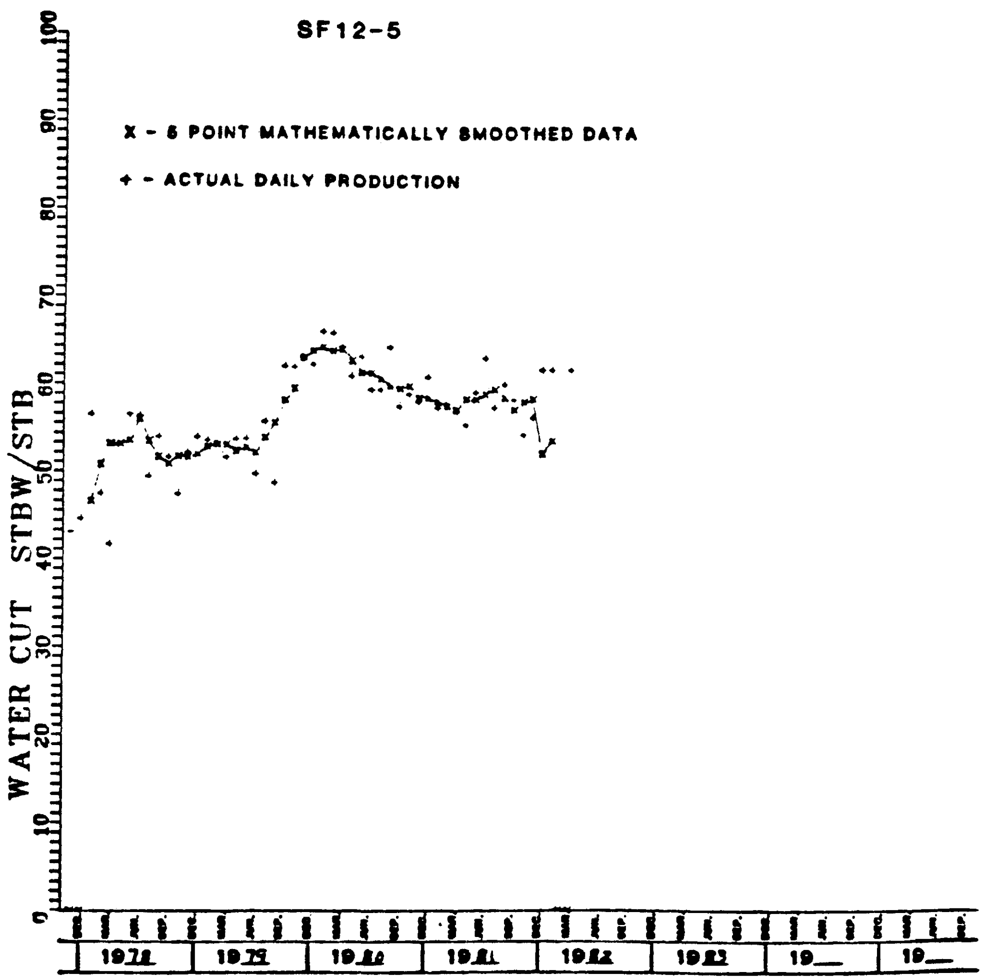


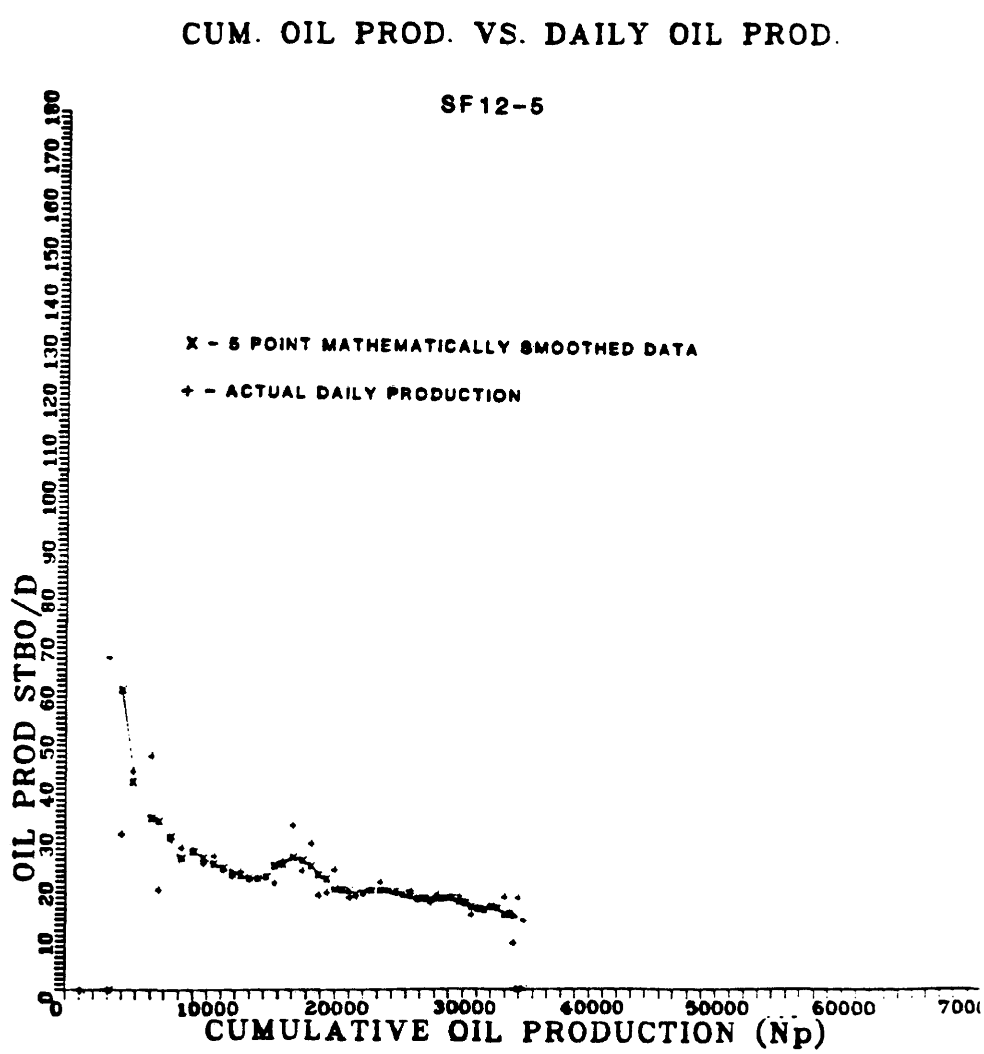
OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION
SF12-5



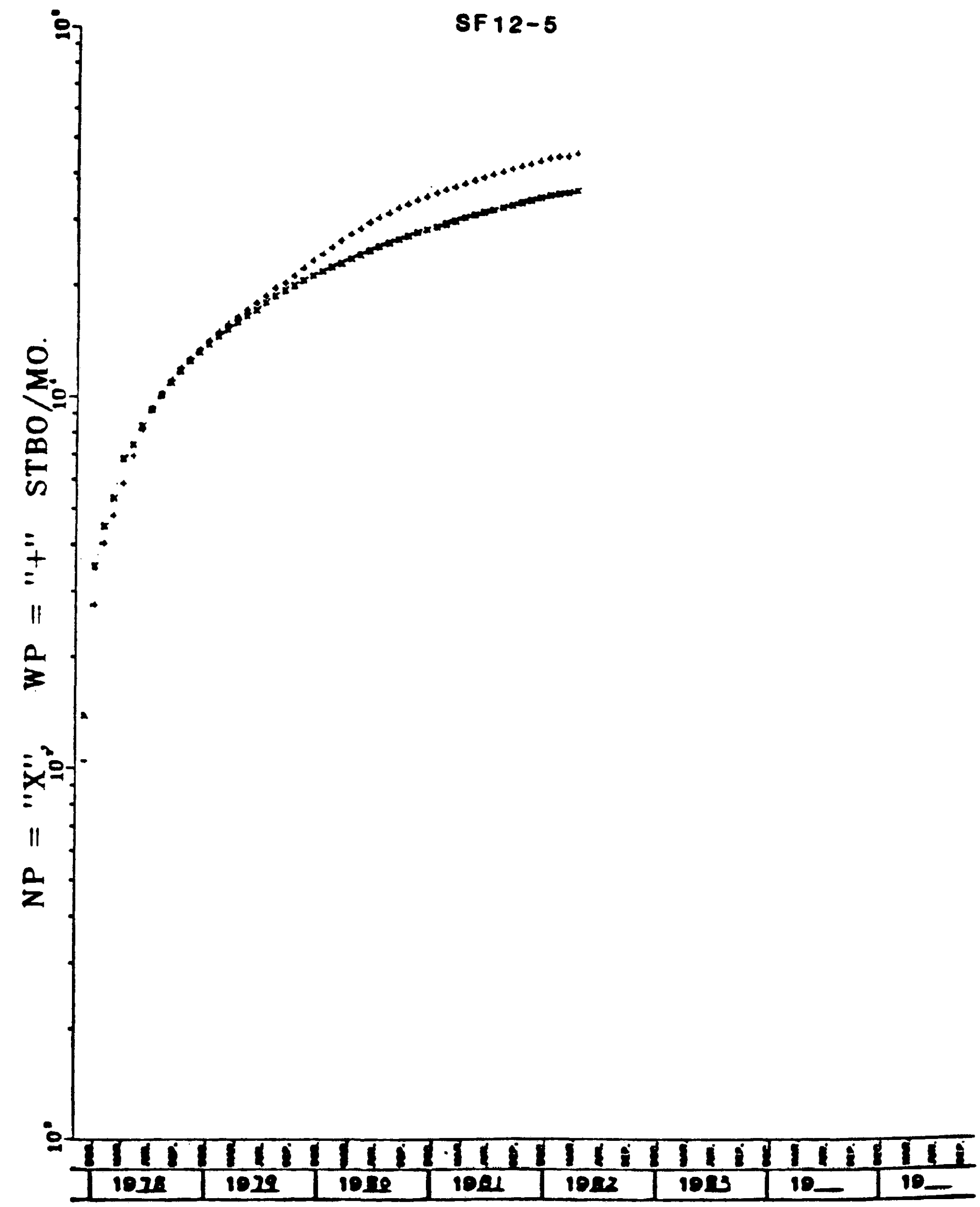

TIME VS. OIL CUT
SF12-5
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL CUT STBO/STB
0
10
20
30
40
50
60
70
80
90
100
1978
1979
1980
1981
1982
1983
19__
19__

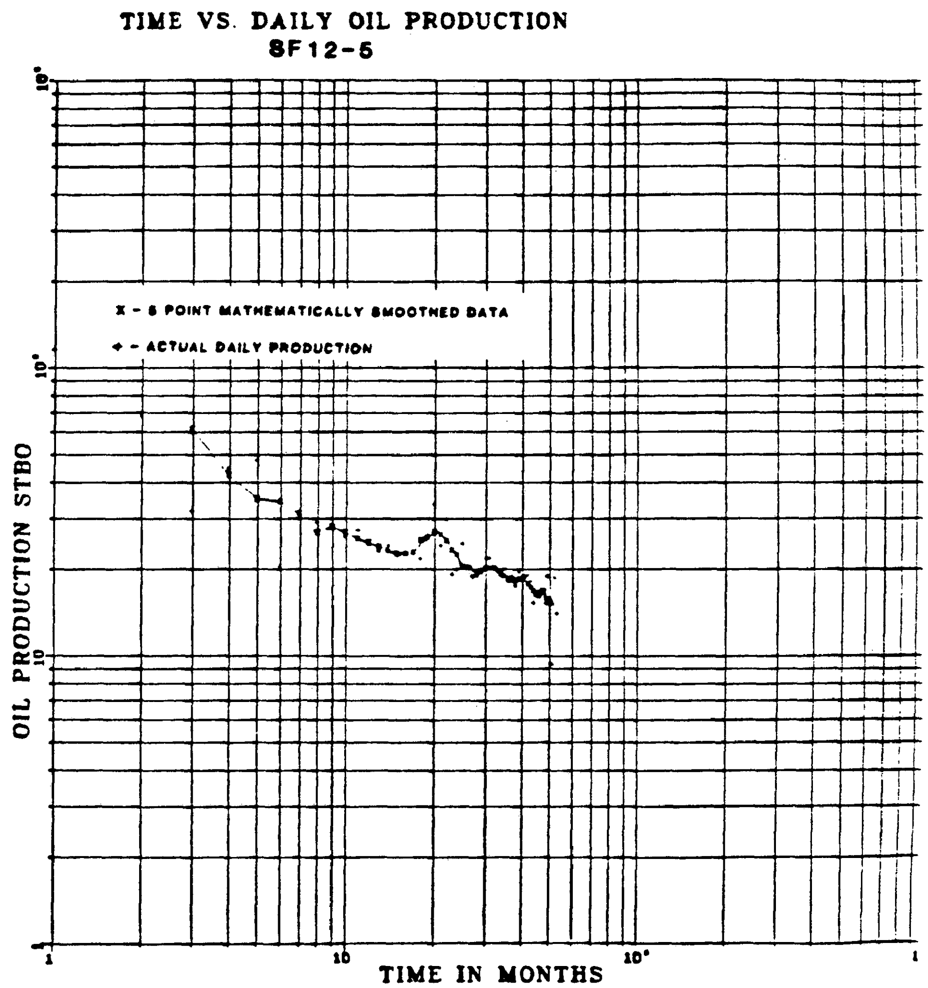
TIME VS. WATER CUT

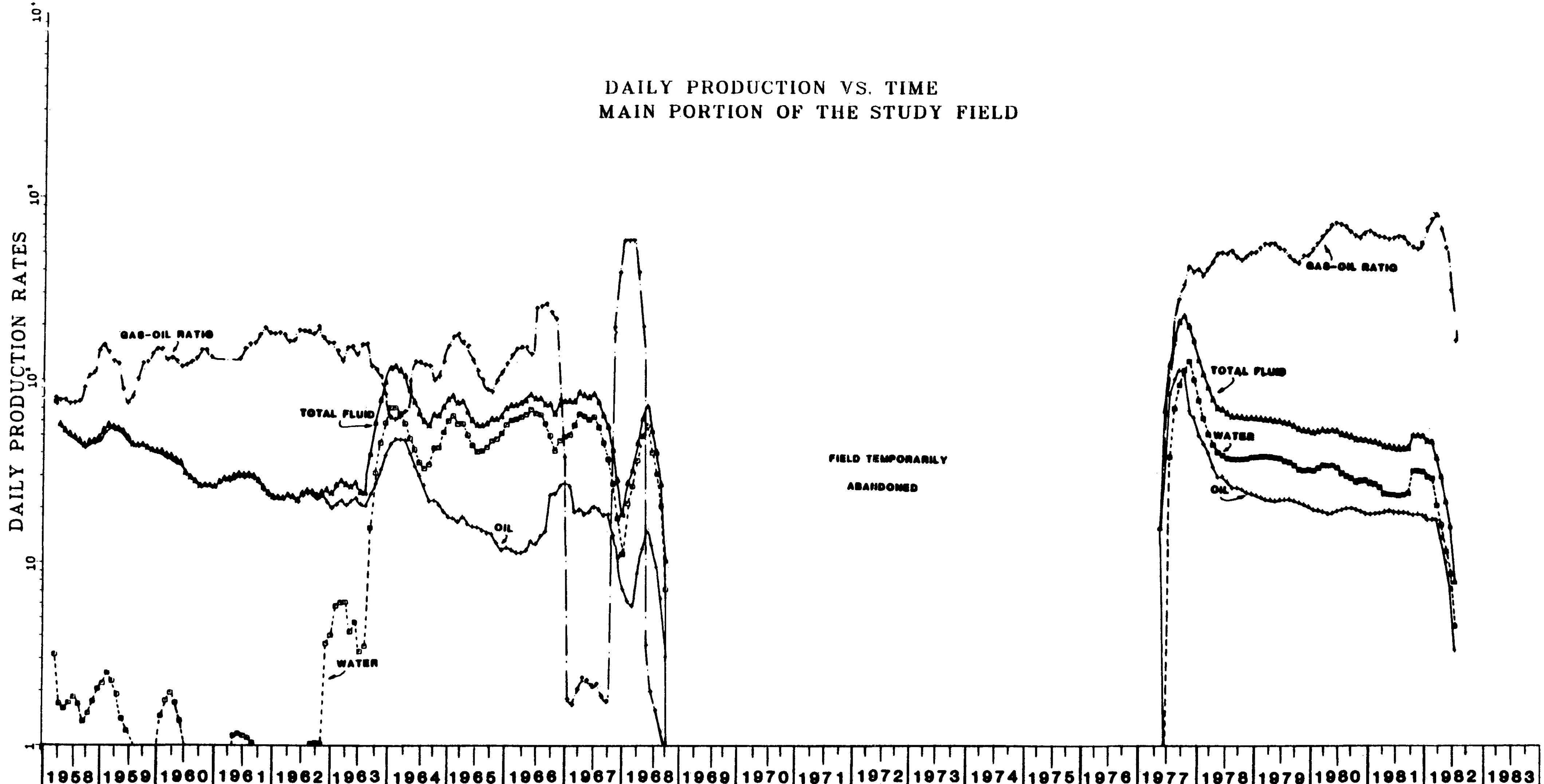


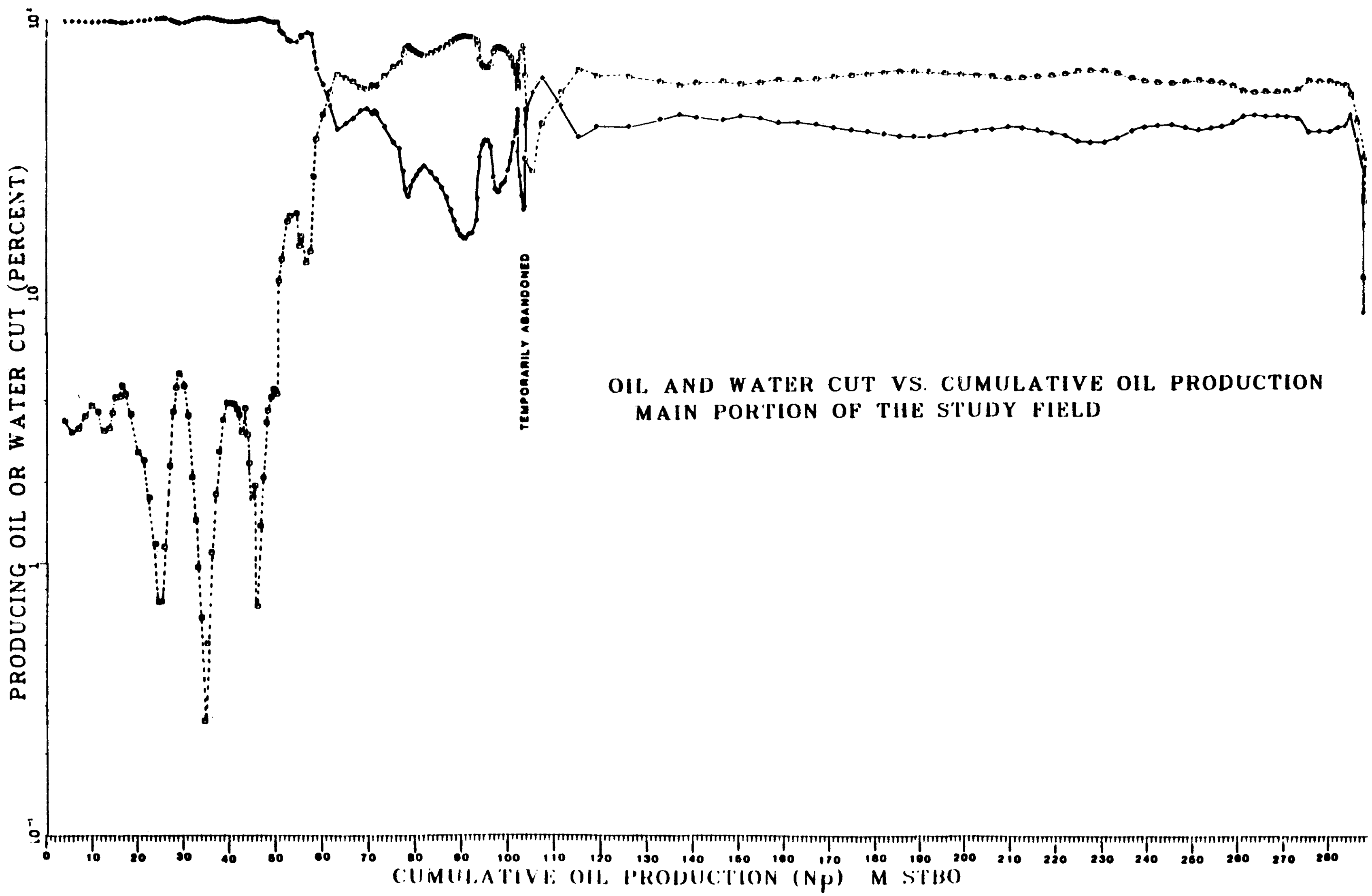

CUM. OIL PROD. VS. DAILY OIL PROD.
SF12-5
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL PROD STBO/D
0 10 20 30 40 50 60 70 80 90 100 110 120 130 140 150 160 170 180
0 10000 20000 30000 40000 50000 60000 7000
CUMULATIVE OIL PRODUCTION (Np)

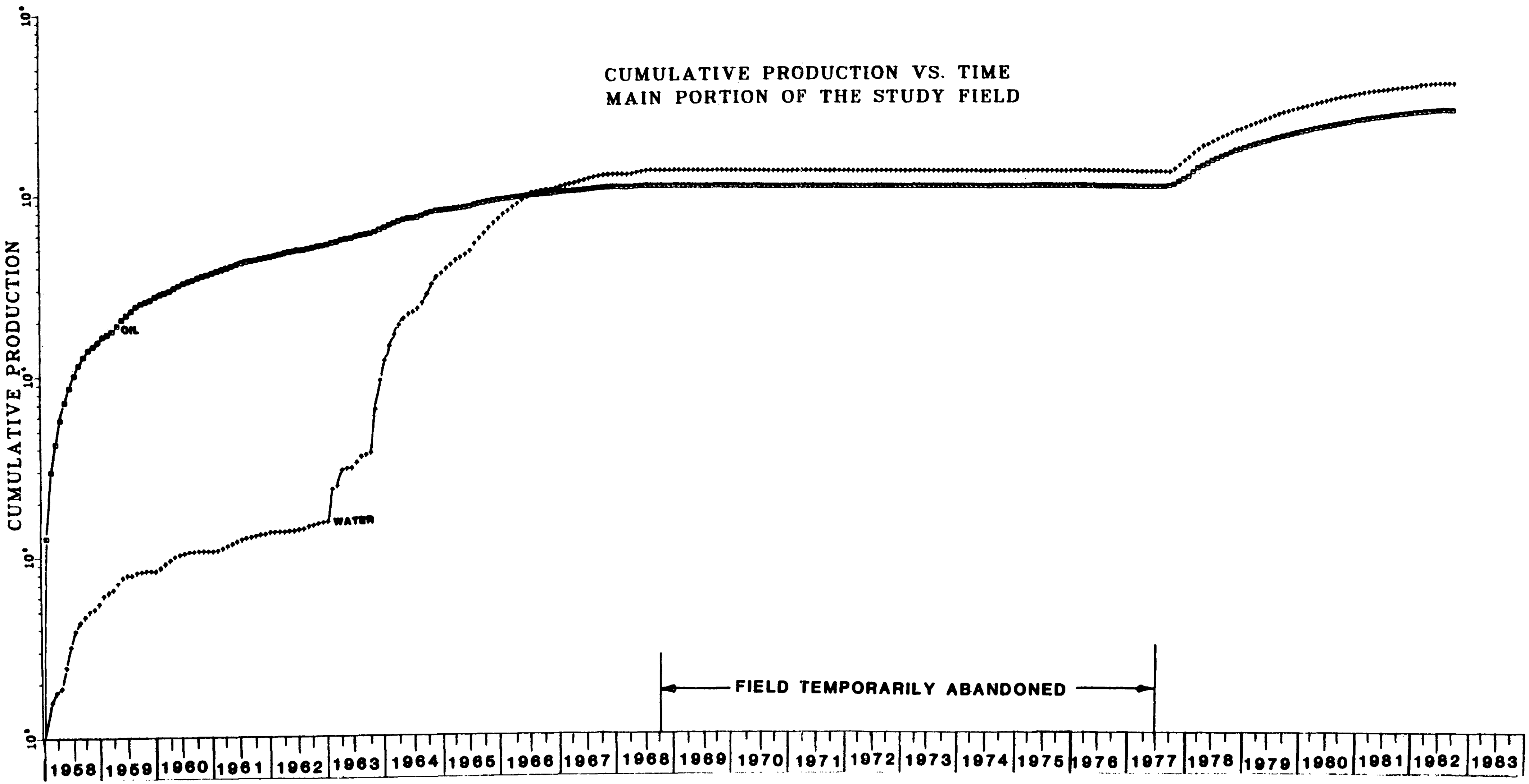
TIME VS. CUM. OIL AND WATER PRODN.




TIME VS. DAILY OIL PRODUCTION
SF12-5
X - 5 POINT MATHEMATICALLY SMOOTHED DATA
+ - ACTUAL DAILY PRODUCTION
OIL PRODUCTION STBO
TIME IN MONTHS


DAILY PRODUCTION VS. TIME
MAIN PORTION OF THE STUDY FIELD
DAILY PRODUCTION RATES
10⁴
10³
10²
10
1
GAS-OIL RATIO
TOTAL FLUID
OIL
WATER
FIELD TEMPORARILY
ABANDONED
GAS-OIL RATIO
TOTAL FLUID
WATER
OIL
1958
1959
1960
1961
1962
1963
1964
1965
1966
1967
1968
1969
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983


OIL AND WATER CUT VS. CUMULATIVE OIL PRODUCTION
MAIN PORTION OF THE STUDY FIELD
PRODUCING OIL OR WATER CUT (PERCENT)
CUMULATIVE OIL PRODUCTION (Np) M STBO
TEMPORARILY ABANDONED


CUMULATIVE PRODUCTION VS. TIME
MAIN PORTION OF THE STUDY FIELD
CUMULATIVE PRODUCTION
OIL
WATER
FIELD TEMPORARILY ABANDONED
1958
1959
1960
1961
1962
1963
1964
1965
1966
1967
1968
1969
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983