NEW MEXICO
OIL CONSERVATION DIVISION

EXHIBIT 15

CASE NO. 10761/10762

RESERVOIR ENGINEERING STUDY

BONE SPRING RESERVOIR, QUERECHO PLAINS FIELD

LEA COUNTY, NEW MEXICO

Prepared for

MEWBOURNE OIL COMPANY

October 1992

Petresim Integrated Technologies, Inc.
Houston, Texas

Petresim
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October 22, 1992

Mr. Ken Calvert
Mewbourne Oil Company
P. O. Box 7698
Tyler, Texas 75711

1456.05

Dear Mr. Calvert:

Reservoir Engineering Study, Bone Spring Reservoir, Querecho Plains Field

This report presents the results of a reservoir engineering study of the Bone Spring reservoir of Querecho Plains field, Lea County, New Mexico, for Mewbourne Oil Company.

The study was performed to determine the expected reservoir performance by depletion and enhanced oil recovery using water injection. This study was authorized by Ken Calvert of Mewbourne and was conducted at the Houston offices of Petresim.

Basic geological and engineering data for the study was provided by Mewbourne and was accepted as presented.

Petresim Integrated Technologies appreciates this opportunity to be of service to Mewbourne Oil Company and hopes this study will be of great use to you.

Sincerely yours,

PETRESIM INTEGRATED TECHNOLOGIES

Petresim Integrated Technologies

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INTRODUCTION

This report presents the results of a reservoir engineering study of the Bone Spring reservoir of Querecho Plains field, Lea County, New Mexico, for Mewbourne Oil Company.

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SUMMARY

A reservoir engineering study of the 1st Bone Spring sand reservoir in the Querecho Plains field located in Lea County, New Mexico, has been completed by Petresim Integrated Technologies (Petresim). The study was performed at the request of Mewbourne Oil Company (Mewbourne Oil) of Tyler, Texas. The purpose of the study was to estimate the primary recovery of hydrocarbons by depletion from the field and to evaluate the feasibility of secondary oil recovery by waterflood from the currently producing area.

The study was conducted using a three-dimensional reservoir model simulator (VIP-ENCORE). The reservoir was modeled as a two-layer, three phase (oil, gas and water) system using a grid of 40 by 41 cells. Basic geological, production, and laboratory data were provided by Mewbourne and accepted as presented.

The original hydrocarbon was characterized as an undersaturated oil with no initial gas cap. The total field original oil-in-place based on the model history match was calculated to be 12.4 MMSTB. Cumulative production as of July 1, 1991, from the field was 1.5 MMSTB of oil, 4.0 Bcf of gas, and 0.4 MMSTB of water.

The original oil-in-place of the currently producing area was determined to be 9.97 MMSTB. Cumulative production as of July 1, 1991, from this area was 1.4 MMSTB of oil, 3.8 Bcf of gas, and 0.4 MMSTB of water.

The geologic description of the field and historical oil rates were input to the simulator and water and gas producing rates, along with shut-in pressure measurements were used to history match each producing well in the reservoir. The history match was acheived by altering reservoir parameters which were unknown or uncertain. After the historical information was matched with the simulator, the total ultimate hydrocarbon recovery from pressure depletion of the reservoir was estimated to be 1.86 MMSTB of oil and 6.1 Bcf of natural gas (1.72 MMSTB of oil and 5.9 Bcf from the currently producing area).

The reservoir model was then used to simulate the reservoir performance for secondary recovery by waterflooding. After preliminary investigations of several injection patterns, the most favorable recovery was obtained from an east-west line drive pattern.

The forecast cases were made assuming waterflood operation would begin July 1, 1992. Producing wells were allowed to produce down to an assumed economic limiting rate of three barrels per day. Water injection rates were limited by a maximum surface pressure of 2000 psia. Individual well rates were based on the wells historical performance. The most favorable water injection case is shown below along with the recovery by depletion:

	PRIMARY DEPLETION		PRIMARY & SECONDARY BY WATER INJECTION	
	PRODUCING AREA	TOTAL RESERVOIR	PRODUCING AREA	TOTAL RESERVOIR
Ultimate Production:				
Oil, MSTB	1,757.4	1,865.6	3,690.0	3,875.0
Gas, MMcf	5,909.9	6,157.6	5,679.4	6,032.4
Water, MSTB	518.1	554.7	15,436	15,518
Total Injection:				
Water, MSTB	0.0	0.0	22,923	22,923
Oil Recovery:				
% of OIP	17.6	15.1	37.8	31.7
Peak Rate:				
Oil, STBD	---	---	784	789
Date	---	---	6/94	6/94

The low primary recovery is due to the fact that there is no additional drive mechanism beyond solution gas drive. The aquifer is too limited to provide any effective pressure support. The relatively low secondary oil recovery can be attributed to the displacement characteristics indicated by the special core analysis laboratory data.

Production profiles for each case were provided to Mewbourne. Economic evaluations were not performed by Petresim. Forecast cases include development and engineering limitations which were provided or agreed to by Mewbourne.

CONCLUSIONS

From the reservoir simulation performed on the Bone Spring reservoir of Querecho Plains field, the following conclusions have been made:

1. The initial oil in place of the total reservoir was estimated to be 12.38 MMSTB with associated gas in place of 11.12 Bcf. The currently producing area comprises 80.5 percent of the initial reservoir volume (9.972 MMSTB).

2. The estimated primary recovery by pressure depletion is 1.86 MMSTB of oil and 6.1 Bcf of natural gas.

3. Implementation of a waterflood program will increase the ultimate oil recovery by approximately two million barrels and extend the economic life of the field by an estimated 15 to 20 years.

4. The currently producing area wells recover approximately 95 percent of the total reservoir production during waterflood operations.

DISCUSSION

GENERAL

The Querecho Plains field is located in Lea County, New Mexico approximately 40 miles west of Hobbs. Figure 1 is a location plat of Querecho Plains field. The reservoir was discovered in 1958 by the Querecho Plains No. 2 well which produced until the late 1960's. A total of 43 wells have been identified as having produced from the Bone Spring reservoir in the Querecho Plains field. Most of these wells were drilled in the early to mid-1980's on federal leases in the southern portion of Township 18 South, Range 32 East. Development wells have been drilled on 40-acre spacing.

GEOLOGY

The Bone Spring reservoir in the Querecho Plains field is characterized by three sand members locally referred to as the 1st, 2nd, and 3rd Bone Spring sands. The 1st Bone Spring sand can be divided into several members, two of which are targeted for waterflooding, those Mewbourne refers to as the green sand (upper member) and the blue sand (lower member). These two members can be mapped across the field at measured depths of between 8,300 ft and 8,500 ft. The structure, as mapped by Mewbourne Oil, is shown on Figure 2. The Bone Spring has a regional northwest to southeast dip with approximately 260 ft of closure. A zero-capillary-pressure level is estimated at -4,875 ft ss, and is supported by high water-cut wells in the southeast end of the field. The north, east, and west boundaries of the field consist of stratigraphic pinchouts of porosity and/or permeability. The southwestern portion of the field appears to be in a area of lesser dip and is possibly isolated by a lack of net porus rock between Sections 34 and 35.

Net Pay

Net Pay was calculated for each sand member by Mewbourne using downhole logs and the limited amount of core data available. A porosity cutoff of 8 percent was used for determining net pay. A map of net sand thickness for each sand member of the 1st Bone Spring prepared by Mewbourne Oil is presented in Figures 3 and 4, respectively.

Porosity

Porosity values were calculated for each sand member from the available logs, neutron-density and/or sonic logs. Porosity trends appear to conform to depositional trends with higher porosity in the center of the field and decreasing near the edge.

RESERVOIR ROCK AND FLUID CHARACTERISTICS

Permeability

Permeability data were available from core taken in the Mewbourne Federal L-4 well. These data were statistically evaluated and used for estimating an initial permeability distribution. The permeability and porosity values were correlated and initial estimates for permeability were calculated from the porosity distribution. A plot of permeability values versus porosity values is shown in Figure 5. A separate relationship was used for each sand member in the simulation. The average porosity value from the core was 11.4 percent, the geometric average permeability value was 1.2 md, and the arithmetic average permeability was 2.4 md.

Capillary Pressure and Water Saturation

A special core analysis study performed by Core Laboratories on samples from the Mewbourne Federal L-4 well was available for use in the study. Sample permeabilities ranged from .06 md to 9.2 md, and sample porosities ranged from 7.5 percent to 16.5 percent. The laboratory-measured air-brine capillary pressure curves are shown on Figure 6. Water saturation versus height above the water-oil contact was calculated based on the average data from air-brine capillary pressure tests. Water saturations in the tests with porosity greater than 8 percent ranged from 17.1 percent to 48.5 percent at an air-brine capillary pressure of 100 psi. This corresponds to a height above the oil-water contact of approximately 350 ft at reservoir conditions. An average of 28 percent irreducible water saturation was used in the simulation, which is a porosity-weighted average based on the distribution of porosity in the core.

Relative Permeability

Six core samples were used to test the water-oil relative permeability relationships for the Bone Spring. Two differing tests were conducted, one an unsteady-state relative permeability measurement where water was displacing oil, and one a basic waterflood test conducted with an assumed reservoir water-oil viscosity ratio. The results of the laboratory tests are presented on Figure 7. The samples were used to generate average curves for use in the simulator. Since waterflood evaluation was the goal of the study, pseudorelative permeability relationships for water and oil were calculated based on waterflood performance in a layered material balance model. Calculations were performed using Dykstra-Parson's method and Hearne's method. This accounts for the variation in permeability, initial water saturation, and residual oil saturation observed in the samples used in core analysis. In general, oil recovery from the basic waterflood tests at actual reservoir viscosity ratios was 5 percent of oil in place higher than the recoveries in the relative permeability tests, since the relative permeability tests were conducted using oil with a viscosity of approximately 20 centipoise.

No tests were available for evaluating the relative permeability relationship between gas and oil.

A typical relationship was assumed and adjusted where necessary to match the historical gas-oil-ratio performance from the wells.

Reservoir Fluid Properties

A recombined separator sample from the Federal L-3 well was analyzed by Core Laboratories in 1987. The sample was recombined to a producing gas-oil ratio and found to have a saturation pressure greater than the estimated original reservoir pressure. The sample was subsequently recombined to have a saturation pressure equal to the original pressure in the reservoir. The fluid characteristics were then determined by differential liberation and the properties are shown on Figure 8. The solution gas-oil ratio was 1,135 scf/STB at a saturation pressure of 3338 psig at a temperature of 130°F. The oil formation volume factor was 1.562 by differential liberation. A separator test of the sample yielded a gas-oil ratio of 1,111 scf/STB and a flash-formation-volume factor of 1.557 reservoir barrels per stock tank barrel. The residual oil had an API gravity of 40.4. While the saturation pressure determined from this lab study is approximately equal to the original reservoir pressure, no gas cap has been found.

RESERVOIR SIMULATION

Model Initialization

The Bone Spring reservoir was modeled using the VIP-ENCORE black oil simulator developed by Western Atlas Integrated Software of Houston. A slightly irregular grid system was chosen to accommodate well locations and lease boundaries. A 40 by 41 grid with a total of 1,640 grid blocks (1,103 active), composed of approximately 4.5 acres each over most of the field area, was used to describe the reservoir. A schematic layout of the grid system is shown in Figure 9. The reservoir was described as two layers representing each of the 1st Bone Spring's two sand members. Since most of the wells were fraced, the two sand members were assumed to be in communication with the wellbore in most wells. Maps prepared by Mewbourne Oil were digitized, and values were calculated for each grid cell. Maps included structure of the top of the main sand, net Bone Spring sand, and porosity. Permeability was calculated from the permeability-porosity relationship for each sand member based on core analysis values.

Fluid properties were based on the properties of the Federal L-3 sample, and the water properties at reservoir conditions were estimated from correlations. The original fluids in place, calculated by the model initialization before any adjustments, were 23.6 MMSTB of oil and 26.6 Bscf of gas.

History Match

The history period included all field oil production from the initial discovery date through June 1991. One well produced from 1958 through 1966, and its production was incorporated in the 2 years prior to start of production of the McKay West Federal No. 1, which began sustained production in early 1980. The method used in the history match was to input historical oil production rates of each well and match the gas-oil-ratio behavior, water cut, and reservoir pressure determined by the simulator to the measured historic values. Since no pressure information was available for the field except on certain Mewbourne-operated wells where November 1991 pressure surveys were available, pressure was not a major matching parameter. Once the match of historical production was accomplished, the reservoir model contained a reasonable representation of the oil and gas distribution which existed in the reservoir at the end of the history match period.

To achieve a history match, several parameters were adjusted. Well-cell permeabilities were increased to account for fracture treatments during completion. In addition, overall reservoir permeability was increased above the original values estimated from the core analysis data. This was possibly due to the minimum number of samples analyzed, which could give a less-than-representative profile of the entire reservoir. Producing data from the southwest portion of the field indicates less water production in the wells than expected from the structural position. For this area, a zero-capillary pressure level of -4,900 ft ss was used, and a zero- capillary pressure level of -4,875 ft ss used for the rest of the field.

During history matching, the oil in place was reduced substantially from the oil in place calculated from initial parameters to match the measured gas-oil-ratio data and pressure data. In addition, upon review of initial gas-oil ratios in many wells and the production of the Federal L-3 well prior to sampling, the initial saturation pressure was decreased to 2715 psig. This is based on the fact that no original gas cap has been discovered in the field, and the producing gas-oil ratio initially for many wells was less than 1,000 scf/STB. Well Federal L-3 was sampled after a month of production at rates of greater than 100 bbl/D; thus, it was likely that the bottomhole flowing pressure was below the original bubblepoint when the well was sampled. If this was true, the producing GOR was above the solution GOR when the fluid sample was collected. A saturation pressure of 2715 psi was used, which corresponds to a solution gas-oil ratio of 911 scf/STB.

The gas-oil relative permeability relationships were adjusted to match the gas-oil-ratio performance, since there was no data from the special core analysis on gas-oil relative permeability. Figure 10 presents the final data used. Water-oil relative permeability relationships were based on the layered pseudorelative permeability relationships discussed earlier. The residual oil saturations were adjusted to account for the displacable oil volume, which averaged 55 percent of oil in place, indicated by the waterflood susceptibility tests at reservoir conditions. Residual oil saturations were also adjusted slightly (reduced 3 saturation percent) for a reduction in residual oil saturation due to waterflooding with free-gas saturation present.

The field history match through June 30, 1991, was achieved with an original oil in place of 12.4 MMSTB and solution gas of 11.1 Bcf. The total reservoir pore volume was 35.4 MM reservoir barrels with an average water saturation of the entire modeled area of 49.6 percent. The average water saturation in the current producing area was 33 percent. Permeabilities in the model ranged from 0.4 md to 21 md, with 98 percent of the cells below 10 md. The grid-block average porosity ranged from 8 to 16 percent.

The initial fluids in place calculated by the model for the history match are shown as follows:

	LAYER 1		LAYER 2		TOTAL	
	Producing Area	Total Zone	Producing Area	Total Zone	Producing Area	Total Zone
Oil MMSTB	2.928	3.880	7.044	8.500	9.972	12.379
Solution gas, Bcf	2.629	3.483	6.324	7.630	8.953	11.113
Water, MMSTB	1.916	5.202	5.141	12.341	7.057	17.544

The field history match is shown on Figure 11.

FORECAST CASES

Primary Recovery

Wells producing at the end of the history match (June 30, 1991) were allowed to produce under pressure-depletion conditions to an assumed economic limit of 5 BOPD. Ultimate recovery from primary recovery was projected by the model to be 1.9 MMSTB of oil and 6.1 Bcf of natural gas through the year 2000, or 15 percent of the original oil in place. The hydrocarbon average pore-volume-weighted reservoir pressure at the end of depletion is 806 psia for the field and 705 psia for the current producing area. Figure 12 shows the field production performance for the depletion case of the Bone Spring reservoir and the projection is tabulated in Table 1.

Waterflood Performance Projections

Once an acceptable history match was obtained, the reservoir simulator was used to project future performance of the reservoir under different water injection patterns. Wells producing at the end of the history match were allowed to produce under current depletion conditions until July 1, 1992, when water injection operations were assumed to begin. Certain wells which had watered out or been recompleted to other zones were not included in the waterflood cases.

Preliminary analyses of prospective injection patterns were made to determine which injection pattern could yield the best results for waterflood operations. A total of seven injection/production well arrangements were evaluated. The seven patterns included horizontal line-drives oriented east-west, horizontal line-drives oriented diagonally southwest to northeast, a seven-spot pattern, and a peripheral flood. In most cases, the ultimate oil recovery was within 5 percent of the other cases. The case selected, based on recovery and operational considerations, was an east-west horizontal line-drive with 16 injectors and 18 producers.

Forecast guidelines shown in Table 2 were used in each case. All producing wells are assumed to be equipped with pumping units by 1992 and capable of maintaining an average BHFP of 85 psi. Water injection is limited by a 2000 psi surface injection pressure and by a maximum rate per well of 600 BWPD. Each case was forecast for a period of approximately 20 years, with a unit minimum production rate of 100 STB/D.

Selected Case

The selected case is a horizontal (east to west) line-drive with 16 existing wells converted to injectors. There is a total of 18 production wells in this case. A diagram showing the well pattern is presented on Figure 13. A maximum injection rate of 8,613 BWPD occurs in July 1992. A peak oil production rate of 784 BOPD is observed in the quarter ending September 1994. Figure 14 is a graph of the field performance, and Table 3 is a year by year list of the rates. A summary of this case is presented below:

SUMMARY OF SELECTED CASE

INJ TIME	YEAR	OIL STB/D	W.C. %	INJ STB/D	CUM. OIL MSTB	CUM INJ MSTB	SEC* REC MSTB
1 Year	1993	270	.465	5,769	1,708	2,382	—
3 Years	1995	715	.698	3,189	2,195	5,444	330
10 Years	2002	229	.904	2,547	3,193	12,467	1,328
20 Years	2012	108	.944	1,982	3,763	20,704	1,898

* Secondary Recovery Oil

It should be noted that sensitivity cases were run to quantify the effect of shutting in production in the field for a period of 1 year while injecting water, in order to repressure the reservoir before production was begun. This resulted in an increase of oil recovery by a small amount while increasing the peak rate. The economic impact and practical feasibility of this option are beyond the scope of this study.

TABLE 1

FIELD PERFORMANCE RATES FOR DEPLETION CASE

Querecho Plains Field
Lea County, New Mexico

				DAILY PRODUCTION					CUMULATIVE PRODUCTION			PRESSURES, PSIA			GAS LIFT		
DATE	DAYS	YEAR	WELL STAT	OIL STB/D	GAS MSCF/D	WATER STB/D	GOR SCF/ STB	WATER CUT FRAC.	OIL MSTB	GAS MMSCF	WATER MSTB	GRID BLOCK DATUM	BHP DATUM	THP	LIFT RATE MSTB/D	CUM LIFT GAS MMSCF	LIF STATU
30/ 9/91	5020.0	1991.748		376.40	2291.	146.24	6087	.280	1556.37	4101.64	379.52				0.	0.	
31/12/91	5112.0	1992.000		326.62	2039.	135.83	6243	.294	1587.80	4296.23	392.31				0.	0.	
31/ 3/92	5203.0	1992.247		280.73	1777.	123.85	6329	.306	1614.65	4465.36	403.93				0.	0.	
30/ 6/92	5294.0	1992.496		244.44	1569.	114.31	6420	.319	1637.94	4613.98	414.64				0.	0.	
30/ 9/92	5386.0	1992.748		209.73	1358.	105.09	6473	.334	1658.23	4744.94	424.54				0.	0.	
31/12/92	5478.0	1993.000		184.91	1199.	95.08	6484	.340	1675.97	4859.93	433.62				0.	0.	
30/ 6/93	5659.0	1993.496		154.01	1027.	85.10	6670	.356	1706.19	5058.58	449.90				0.	0.	
31/12/93	5843.0	1994.000		129.42	854.63	69.94	6604	.351	1731.79	5228.11	463.84				0.	0.	
30/ 6/94	6024.0	1994.496		104.31	694.64	58.96	6659	.361	1752.12	5363.31	475.02				0.	0.	
31/12/94	6208.0	1995.000		87.26	592.52	52.81	6790	.377	1769.56	5480.31	485.35				0.	0.	
30/ 6/95	6389.0	1995.496		77.19	533.84	45.40	6916	.370	1784.65	5583.46	494.58				0.	0.	
31/12/95	6573.0	1996.000		68.49	475.28	43.33	6939	.387	1797.82	5674.62	502.69				0.	0.	
30/ 6/96	6755.0	1996.496		50.78	356.72	34.84	7025	.407	1808.89	5751.75	509.97				0.	0.	
31/12/96	6939.0	1997.000		44.16	314.20	32.80	7115	.426	1817.28	5811.23	516.09				0.	0.	
30/ 6/97	7120.0	1997.496		42.73	305.95	32.33	7160	.431	1825.12	5867.21	521.97				0.	0.	
31/12/97	7304.0	1998.000		36.49	258.55	28.28	7086	.437	1832.52	5920.11	527.64				0.	0.	
30/ 6/98	7485.0	1998.496		35.64	254.18	28.02	7131	.440	1839.04	5966.44	532.73				0.	0.	
31/12/98	7669.0	1999.000		34.81	249.93	27.74	7180	.443	1845.51	6012.75	537.86				0.	0.	
30/ 6/99	7850.0	1999.496		33.98	245.56	27.43	7227	.447	1851.72	6057.52	542.85				0.	0.	
31/12/99	8034.0	2000.000		33.13	241.17	27.10	7278	.450	1857.88	6102.23	547.86				0.	0.	
30/ 6/00	8216.0	2000.496		17.49	120.37	14.63	6883	.455	1862.45	6135.64	551.97				0.	0.	
31/12/00	8400.0	2001.000		17.17	118.99	14.53	6929	.458	1865.63	6157.63	554.65				0.	0.	

LOCATION PLAT

Querecho Plains Field
Lea County, New Mexico

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February, 1992

FIGURE 1

QUERECHO PLAINS FIELD
LEA CO., NEW MEXICO
STRUCTURE-TOP OF BLUE ZONE

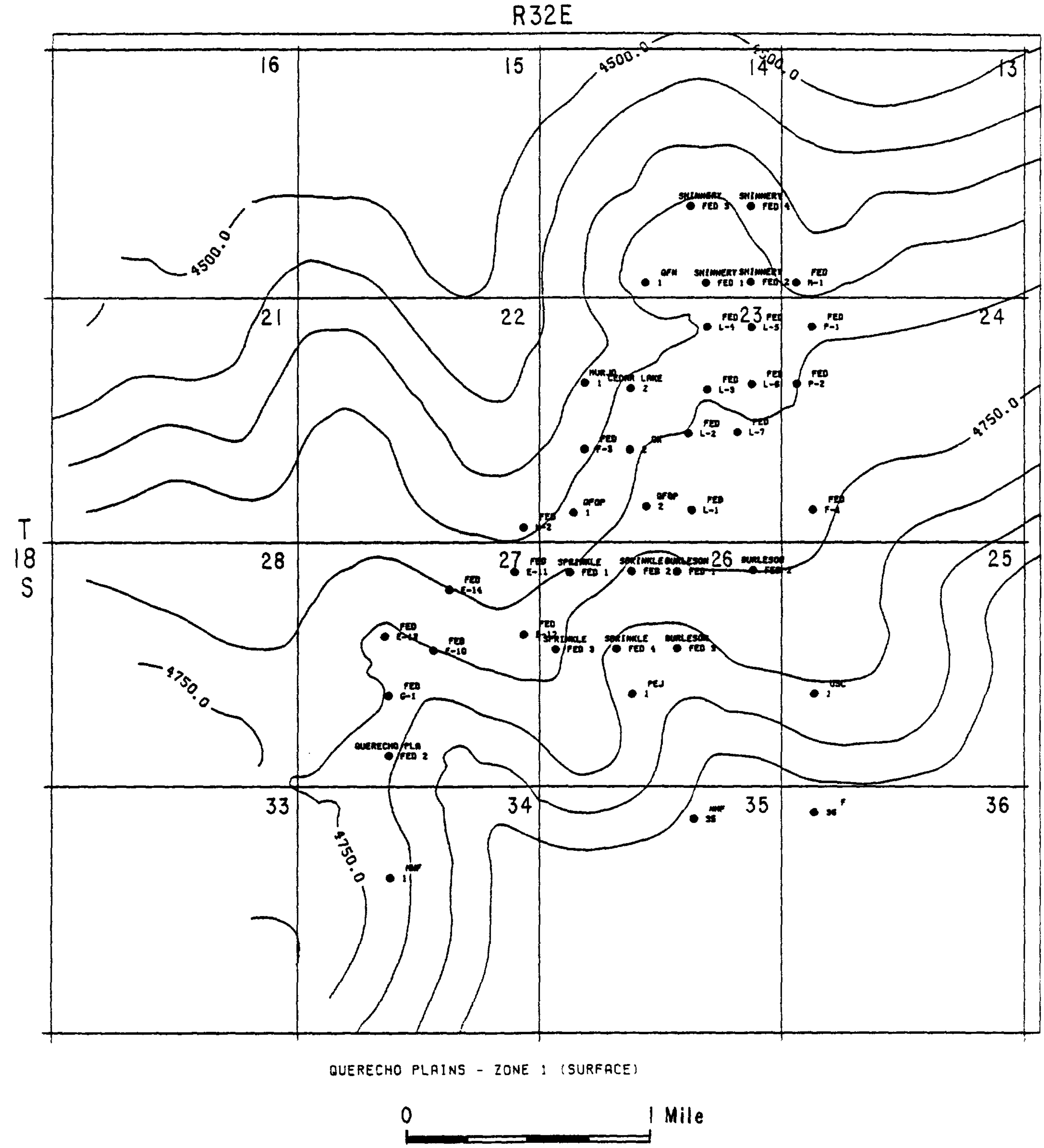

FIGURE 2

QUERECHO PLAINS FIELD
LEA CO., NEW MEXICO
NET SAND-GREEN ZONE

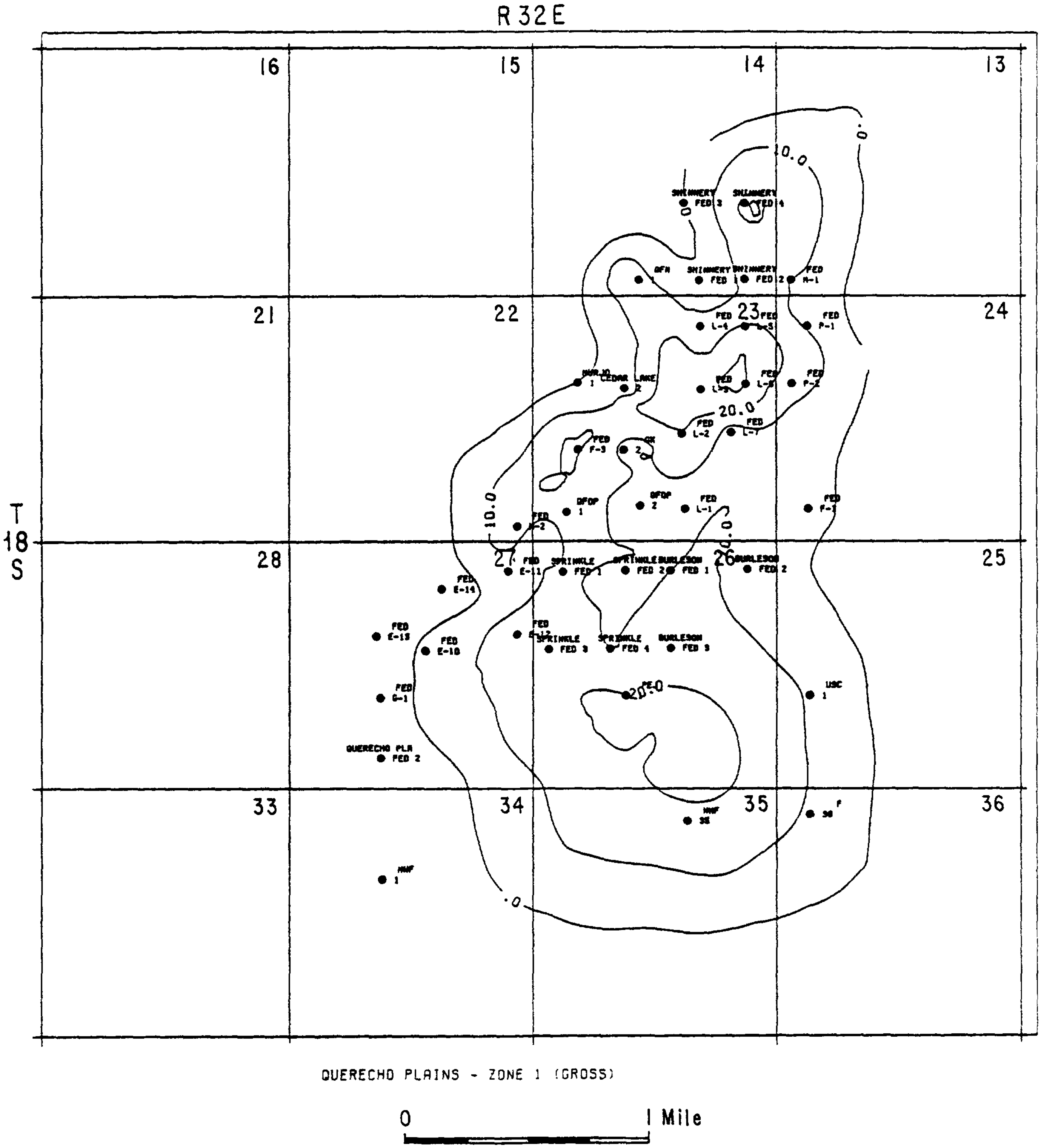

FIGURE 3

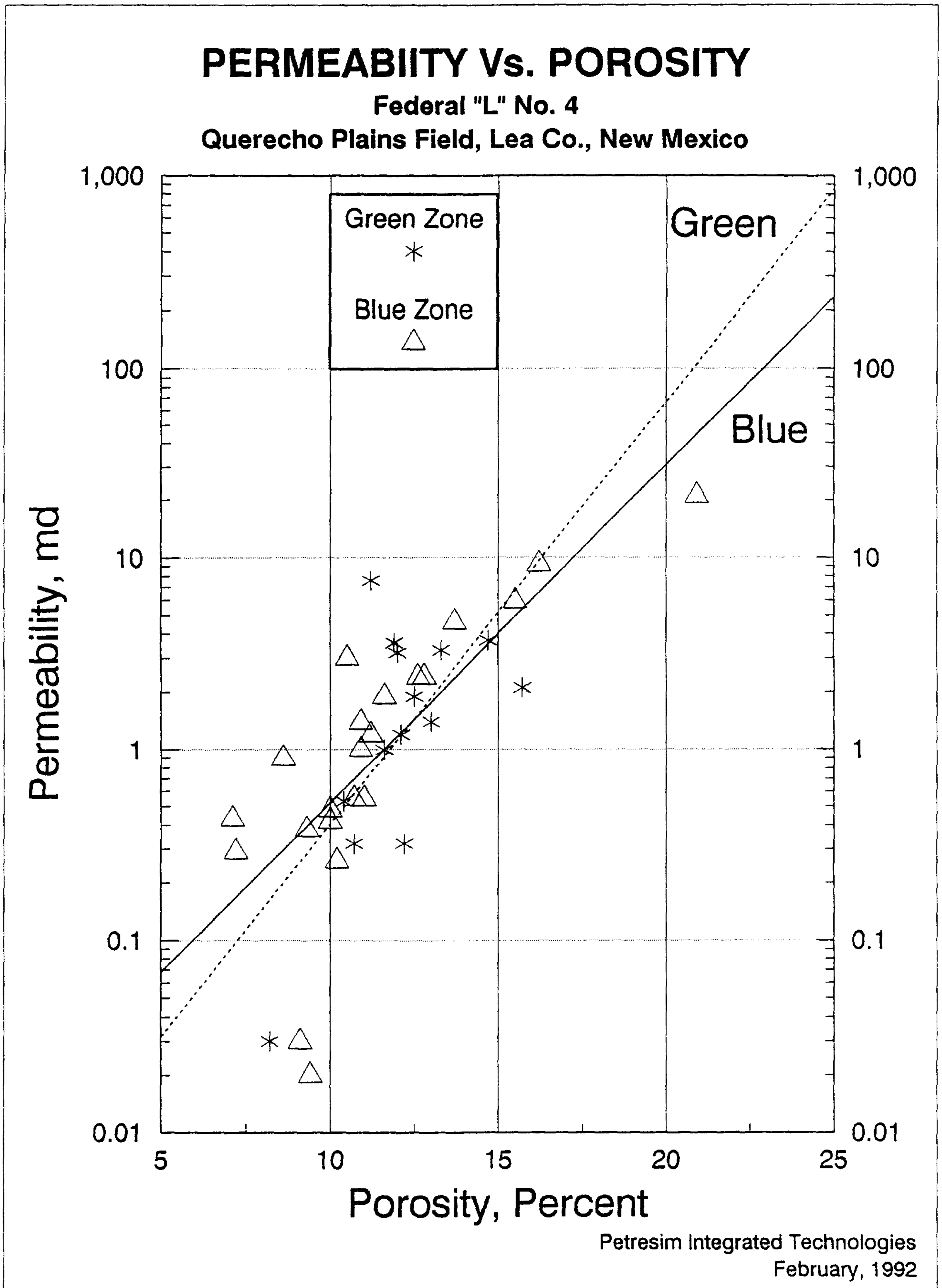
PERMEABIITY Vs. POROSITY
Federal "L" No. 4
Querecho Plains Field, Lea Co., New Mexico
Green Zone
Blue Zone
Green
Blue
Permeability, md
1,000
100
10
1
0.1
0.01
5
10
15
20
25
Porosity, Percent
Petresim Integrated Technologies
February, 1992

FIGURE 5

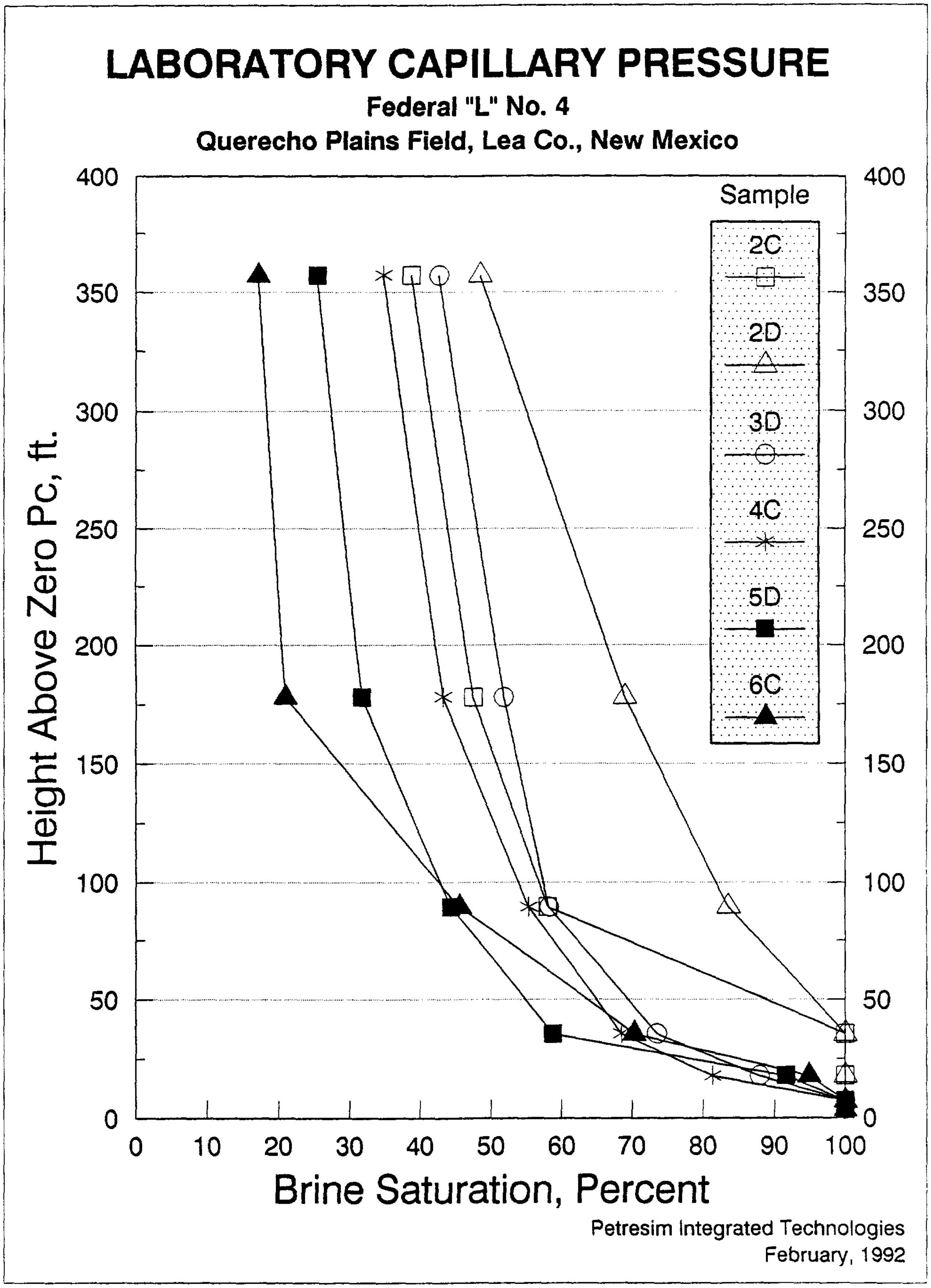
LABORATORY CAPILLARY PRESSURE
Federal "L" No. 4
Querecho Plains Field, Lea Co., New Mexico
Sample
2C
2D
3D
4C
5D
6C
Height Above Zero Pc, ft.
Brine Saturation, Percent
0
50
100
150
200
250
300
350
400
0
10
20
30
40
50
60
70
80
90
100
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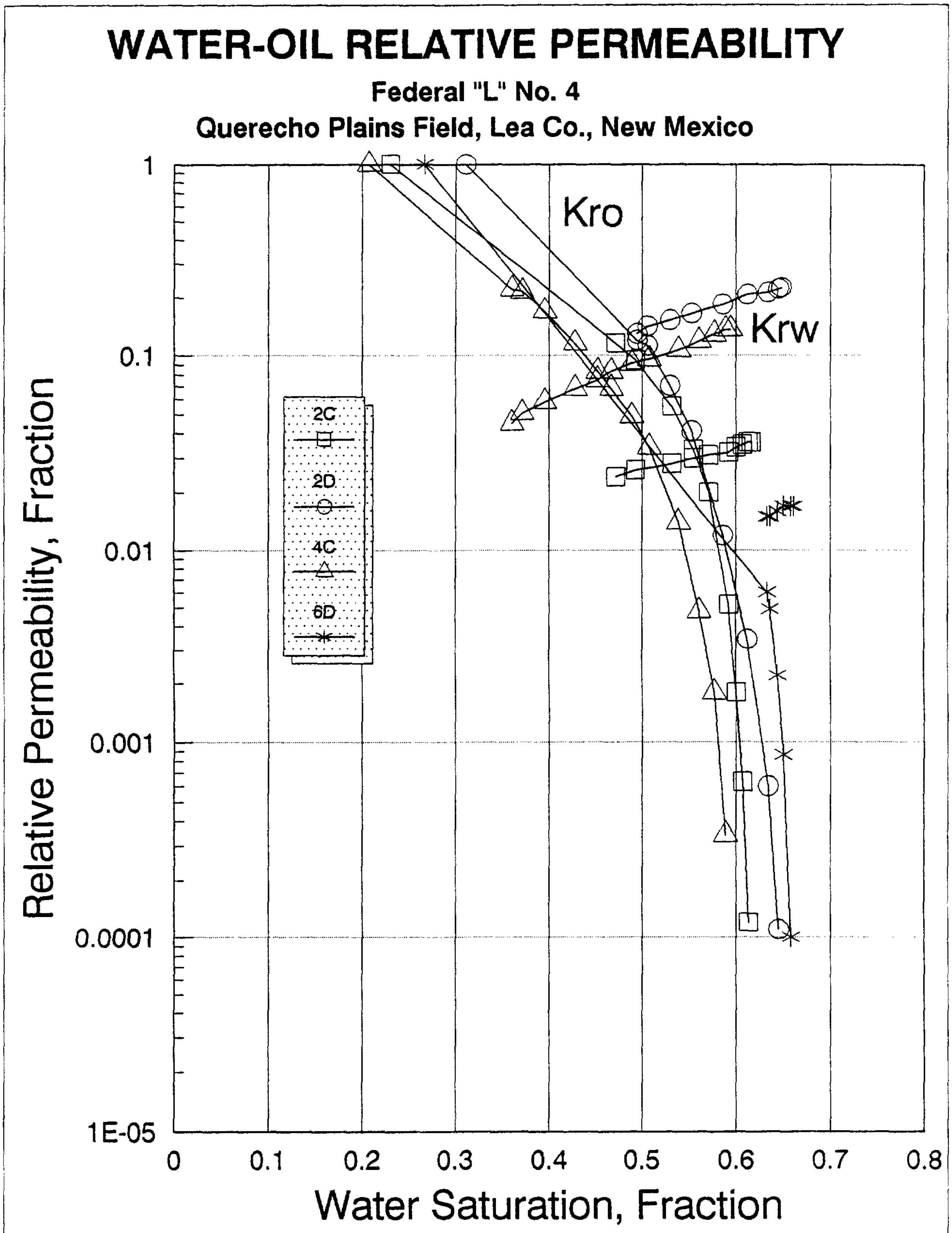
FIGURE 6



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February, 1992

FIGURE 7

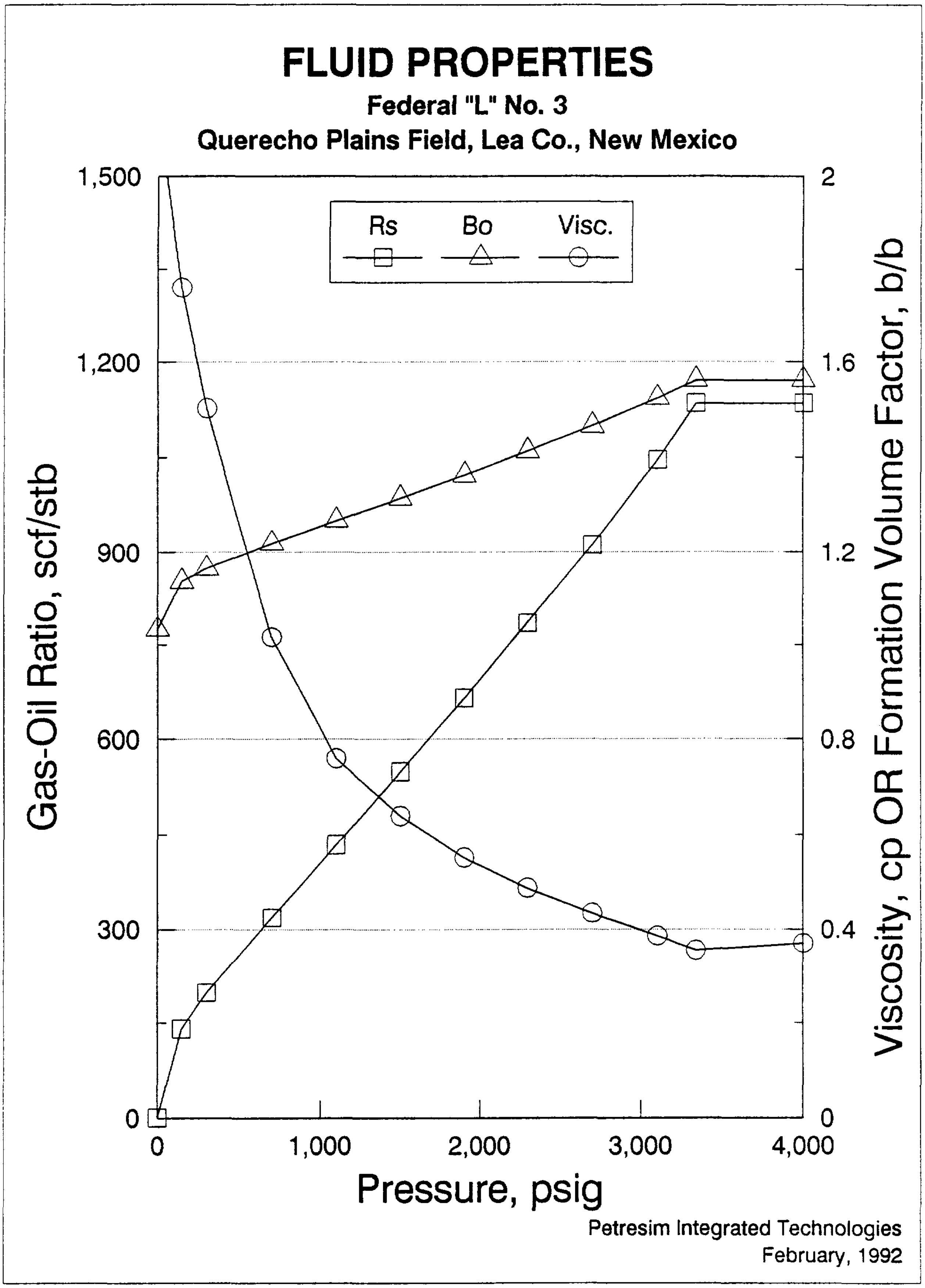

FLUID PROPERTIES
Federal "L" No. 3
Querecho Plains Field, Lea Co., New Mexico
Rs
Bo
Visc.
1,500
1,200
900
600
300
0
Gas-Oil Ratio, scf/stb
2
1.6
1.2
0.8
0.4
0
Viscosity, cp OR Formation Volume Factor, b/b
0
1,000
2,000
3,000
4,000
Pressure, psig
Petresim Integrated Technologies
February, 1992

FIGURE 8

QUERECHO PLAINS FIELD
LEA CO., NEW MEXICO
GRID PATTERN MAP

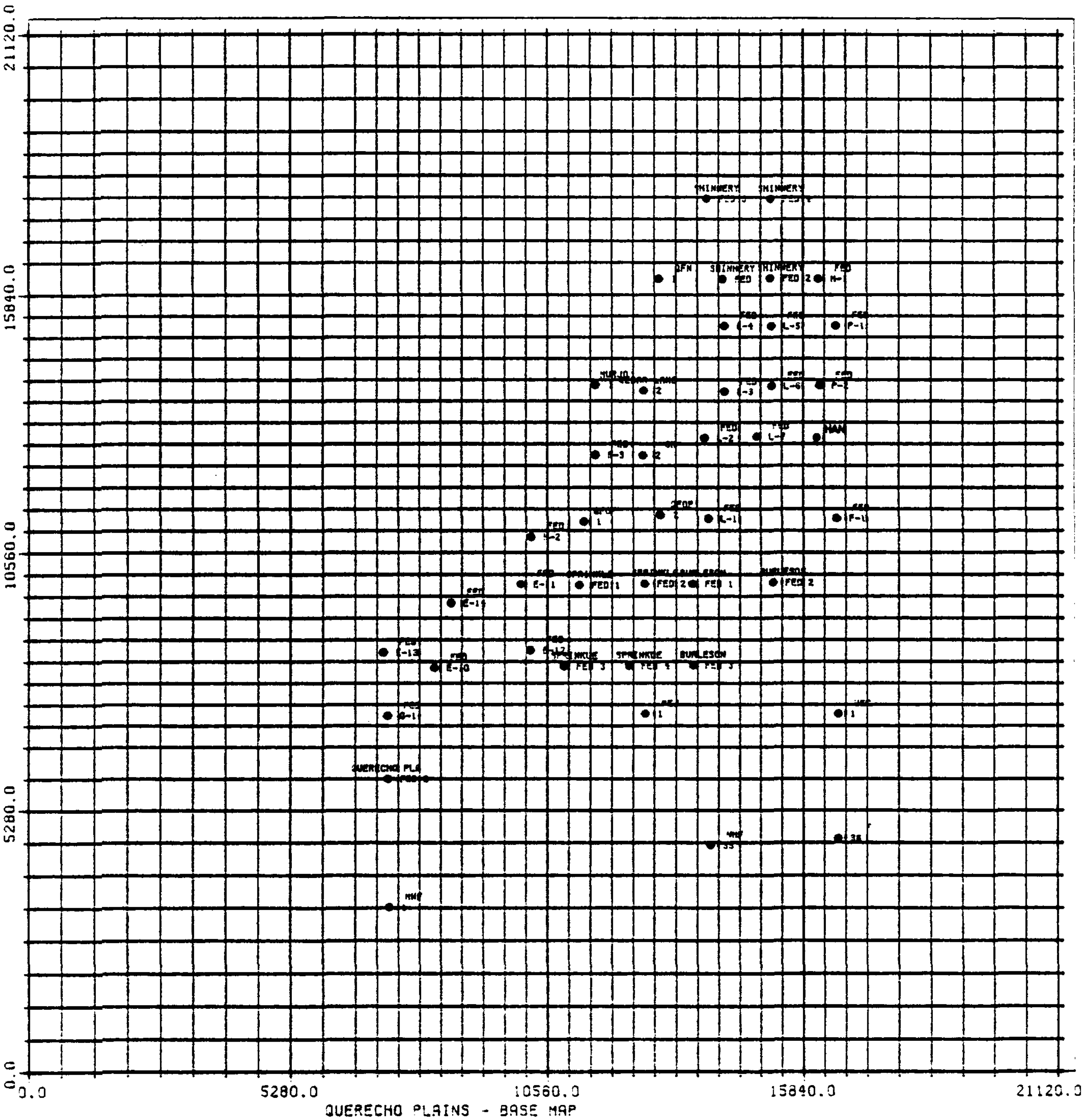


FIGURE 9

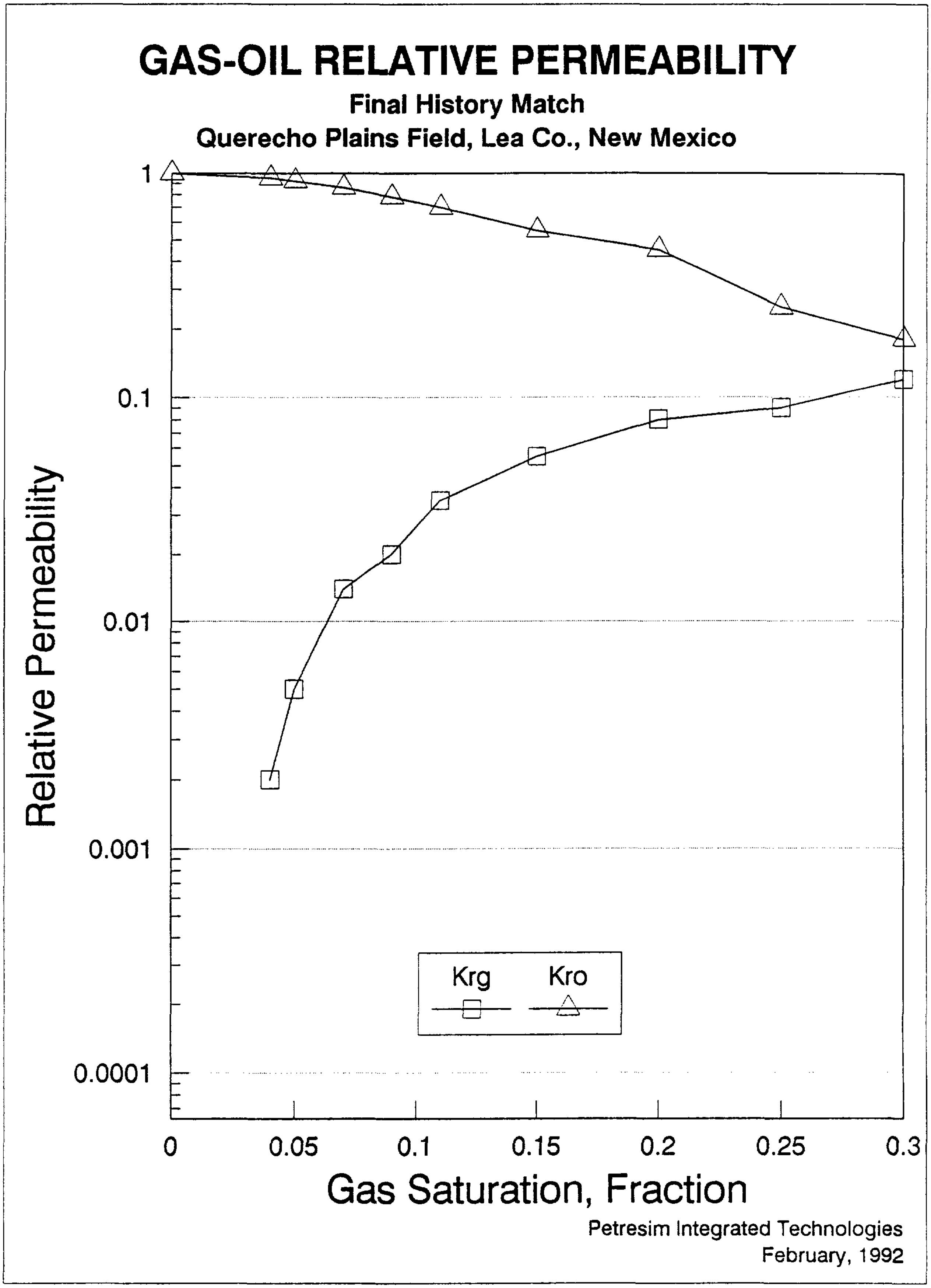

GAS-OIL RELATIVE PERMEABILITY
Final History Match
Querecho Plains Field, Lea Co., New Mexico
Relative Permeability
1
0.1
0.01
0.001
0.0001
0
0.05
0.1
0.15
0.2
0.25
0.3
Gas Saturation, Fraction
Krg
Kro
Petresim Integrated Technologies
February, 1992

FIGURE 10

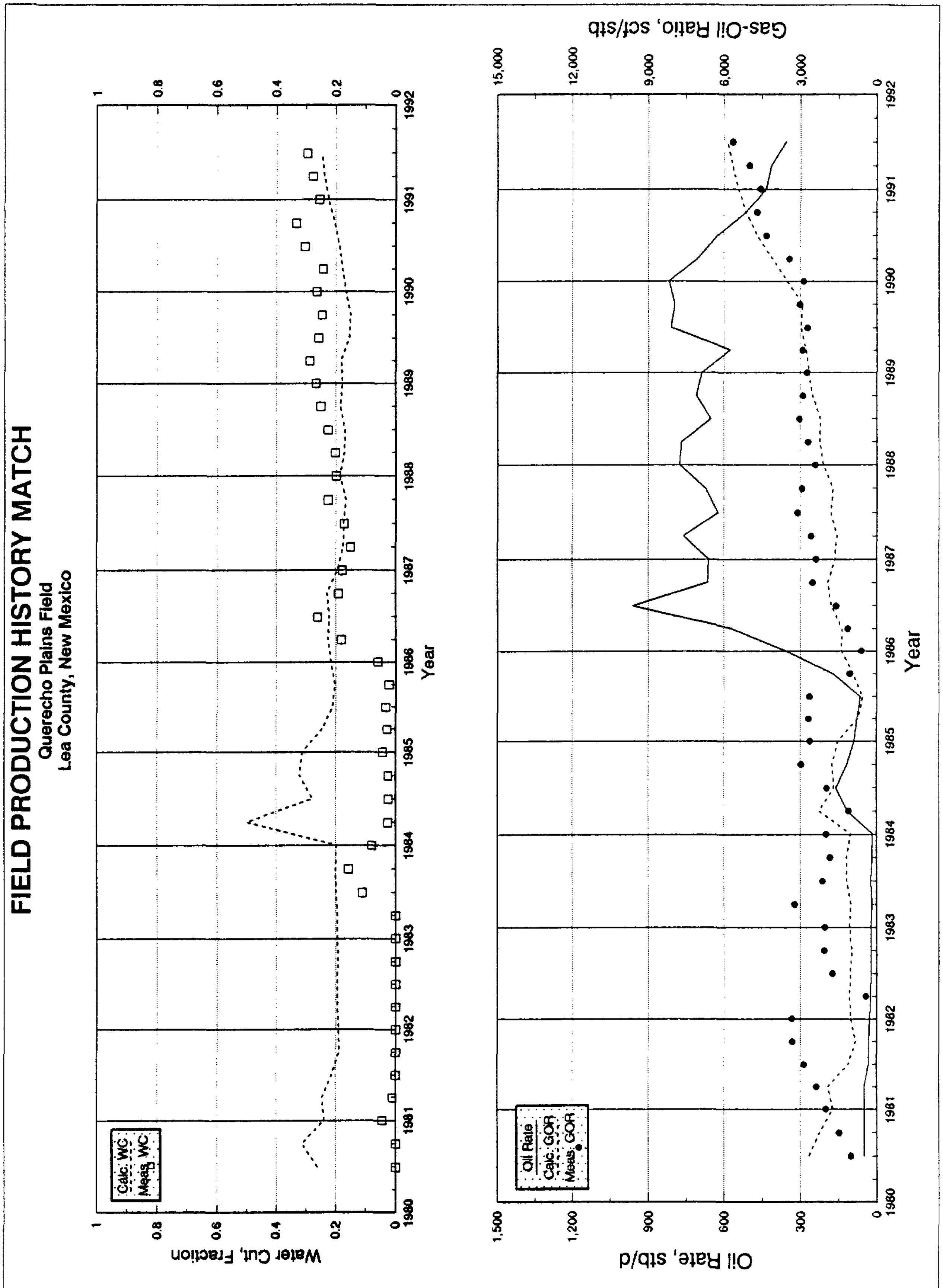
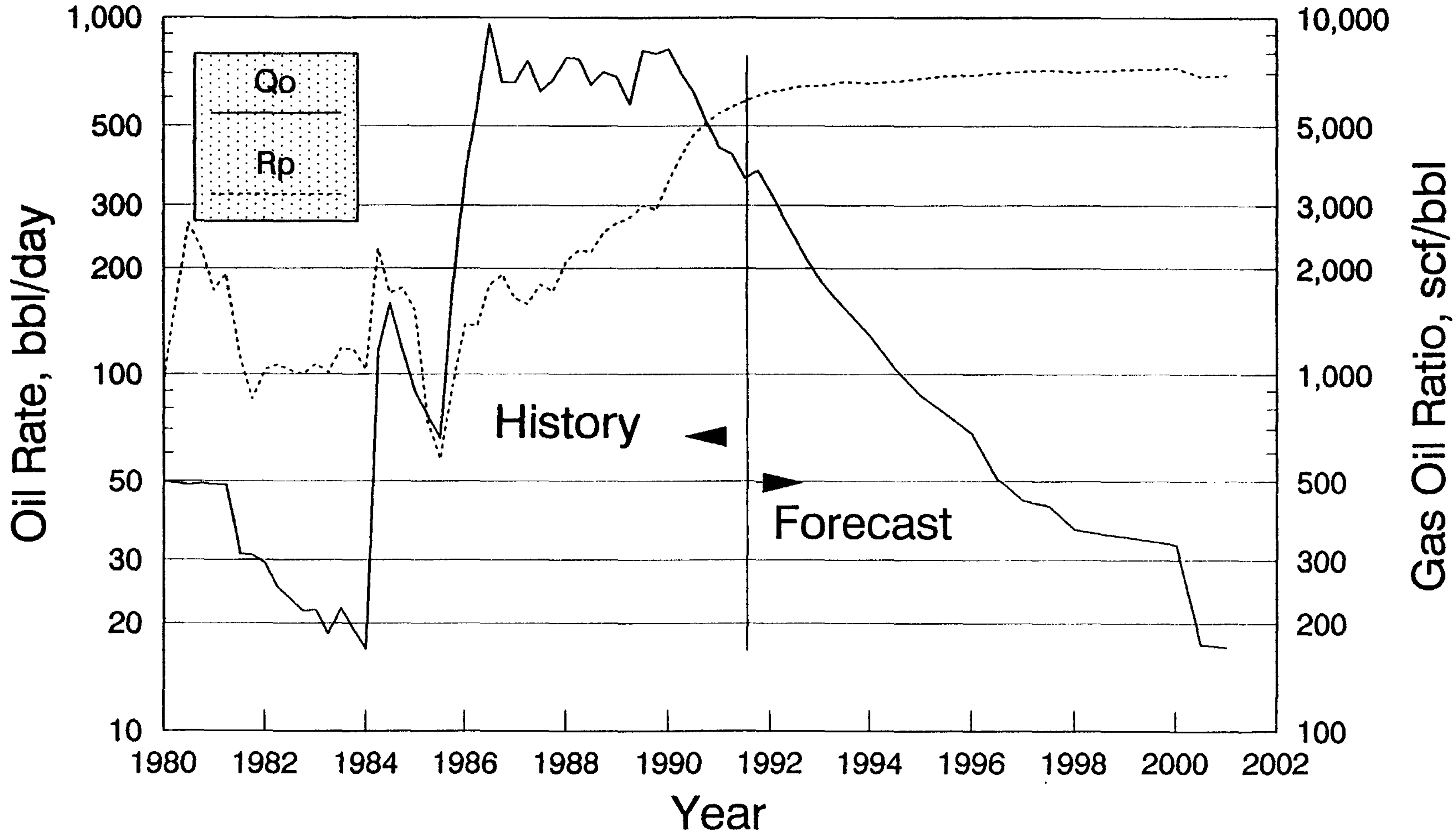

FIELD PRODUCTION HISTORY MATCH
Querecho Plains Field
Lea County, New Mexico
Calc. WC
Meas. WC
Water Cut, Fraction
Year
Oil Rate
Calc. GOR
Meas. GOR
Oil Rate, stb/d
Gas-Oil Ratio, scf/stb
Year

FIGURE 11

FIELD PERFORMANCE - DEPLETION CASE

Querecho Plains Field
Lea County, New Mexico



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February, 1992

FIGURE 12

QUERECHO PLAINS FIELD
LEA CO., NEW MEXICO
WELL PATTERN-INJECTION CASE

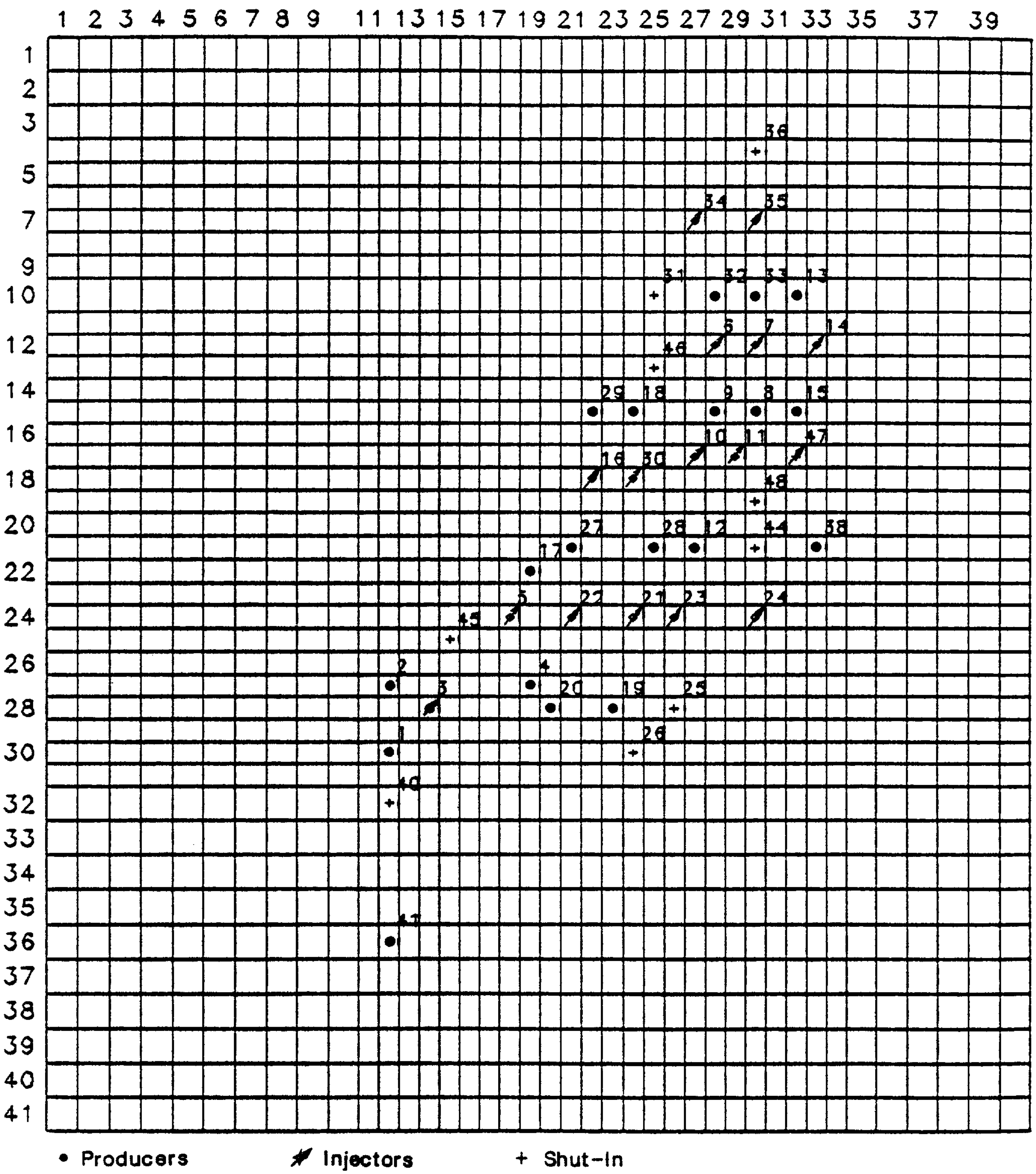

FIGURE 13

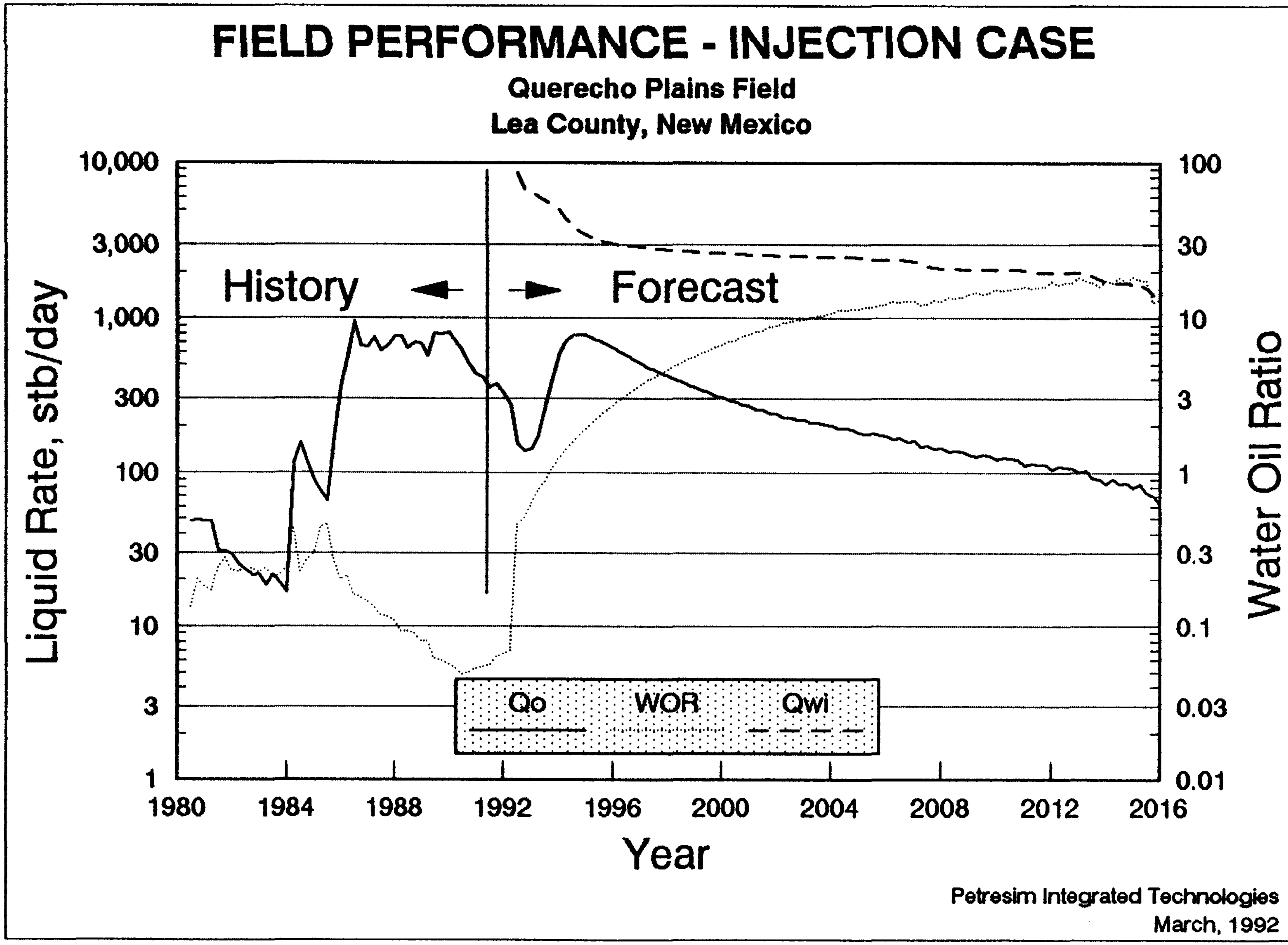
FIELD PERFORMANCE - INJECTION CASE
Querecho Plains Field
Lea County, New Mexico
History
Forecast
Liquid Rate, stb/day
10,000
3,000
1,000
300
100
30
10
3
1
Water Oil Ratio
100
30
10
3
1
0.3
0.1
0.03
0.01
1980
1984
1988
1992
1996
2000
2004
2008
2012
2016
Year
Qo
WOR
Qwi
Petresim Integrated Technologies
March, 1992

FIGURE 14