BENSON-MONTIN-GREER DRILLING CORP.
EXHIBITS IN CASE NOS. 7980, 8946, 8950 AND 9111
BEFORE THE OIL CONSERVATION COMMISSION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

JUNE 13, 1988

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No. 7980, 8946, 8950, 9111, 9412 Exhibit No. 3
Submitted by BMG
Hearing Date JUNE 13, 1988

NOTE ON GRAVITY DRAINAGE
NIOBRARA MEMBER OF THE MANCOS FORMATION
WEST PUERTO CHIQUITO AND BOULDER POOLS

Gravity drainage is succinctly summarized by Frick (Reference 1) in two paragraphs as follows:

"Gravity drainage is the self-propulsion of oil downward in the reservoir rock. Under favorable conditions it has been found to effect recoveries of 60 per cent of the oil in place, which is comparable with or exceeding the recoveries normally obtained by water drive. Gravity is an ever-present force in oil fields that will drain oil from reservoir rock from higher to lower levels wherever it is not overcome by encroaching edge water or expanding gas.

Gravity drainage will be most effective if a reservoir is produced under conditions which allow flow of oil only or counterflow of oil and gas.

1. This may be attained <u>under pressure maintenance by crestal-gas injection,</u> which keeps the gas in solution, or

2. It may be attained by a <u>gradual reduction in pressure,</u> so that the oil and gas can segregate continuously by counterflow.

3. It may also be obtained by first producing the reservoir under a depletion-type mechanism until the gas has been practically exhausted, then by gravity drainage.

A thorough discussion of the many aspects of gravity drainage will be found in the classic paper by Lewis." (Method numbers and emphasis supplied.)

In the fractured Niobrara, because of its unfavorable Kg/Ko relation and the exceptionally high rate of decline of oil productivity with declining pressures and increasing GOR's the third method of obtaining gravity drainage described by Frick (first depleting the reservoir by solution gas drive and then attempting gravity drainage) is not economically available since the rate of oil production in this formation, following depletion by solution gas drive, is at economically unattractive rates, if not below the economic limit.

This leaves for the Niobrara, then, the other two methods: crestal gas injection, or low production rates. When we examine the fundamental flow relations along with the cost of gas injection, it becomes immediately apparent that crestal gas injection is the better method.

DETAILS OF ANALYSIS

The relation of the flowing fluids with, and without, gravity drainage is given by the Buckley-Leverett fractional flow equation (Reference 2).

$$f_g = \frac{1 - \left[\frac{.488 K A d \sin\alpha}{\mu_o}\right] \times \frac{K_{ro}}{q_t}}{1 + \frac{K_o}{K_g} + \frac{\mu_g}{\mu_o}}$$

where $d = (\rho_o - \rho_g)$

When fg is zero, maximum gravity drainage occurs (Reference 2). Under this condition the value of the denominator then becomes insignificant. By dropping the denominator, substituting hw for A, Koh for K(Kro) and (qo)(Bt) for qt (then W becomes the width along the strike) and solving for qt when fg = 0, the equation becomes:

$$q_o = \frac{.488 \ Koh \ d \ \sin\alpha \ W}{u_o \ B_t}$$

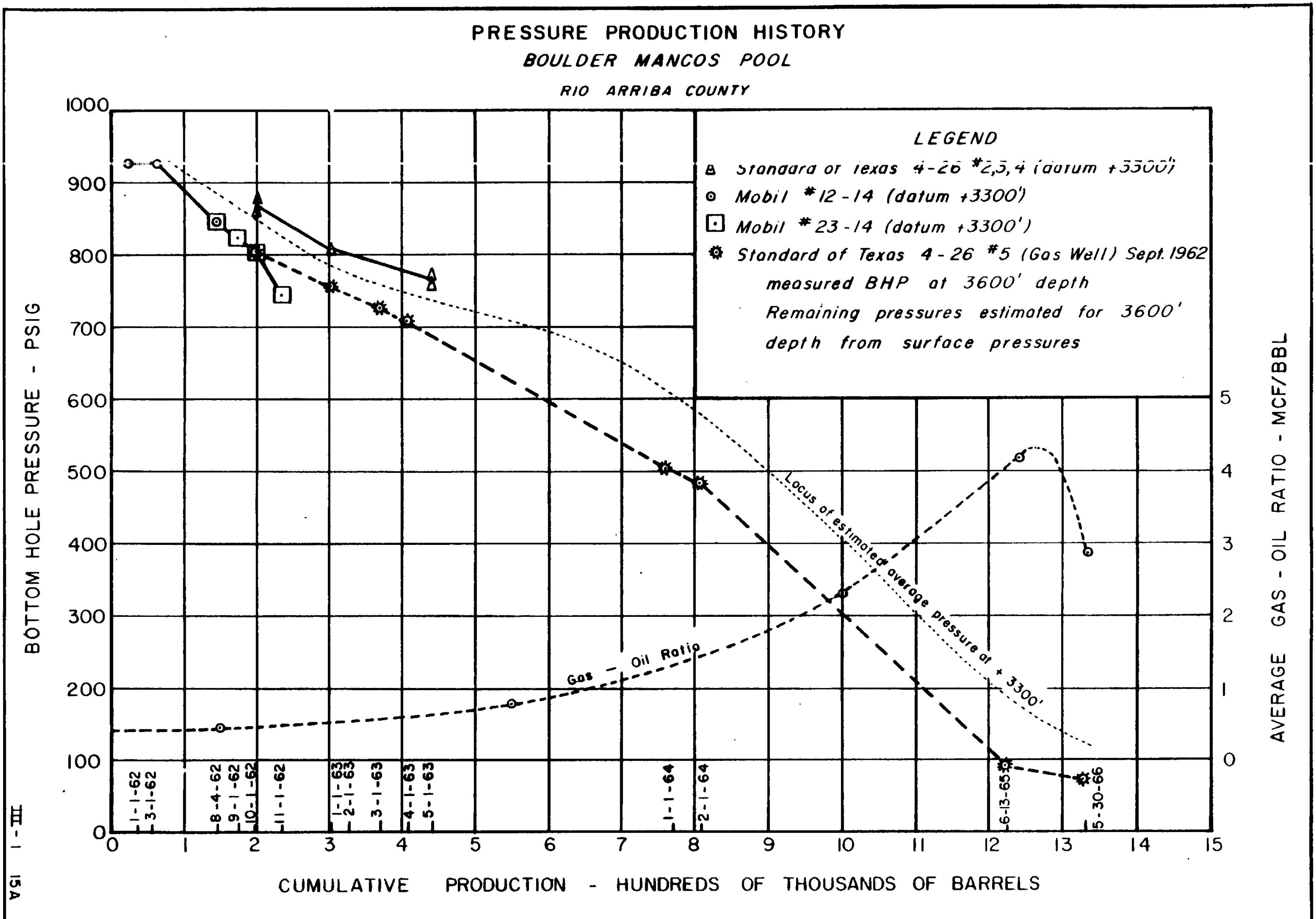
When there is no free gas $B_t = B_o$ = FVF for oil. We then recognize that this is the same formula, derived directly from Muskat's (Reference 3) basic analyses, and provided the Oil Conservation Commission in Case 3455, B-M-G Exhibit 2, Appendix II, Part B, December 1969, which is:

$$q_o = \frac{2580 \ Koh \ d \ \sin\alpha}{u_o \ B_t}$$

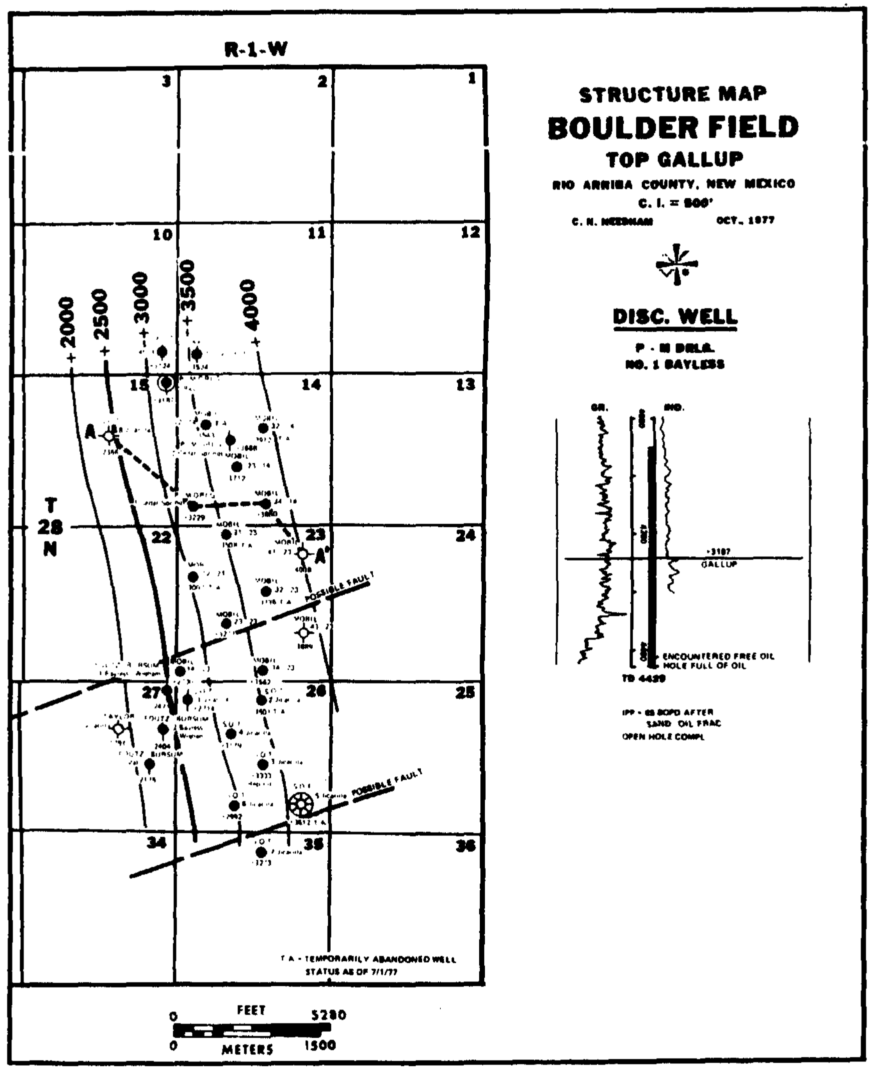
Where q_o = BOPD per linear mile along the strike
Koh = darcy feet
d = diff. in specific gravity of oil and gas (water = 1.0)
α = angle of dip
u = oil viscosity, cp

(where W = 5280, distance along strike)

On the following pages, the Boulder Pool production is compared with its gravity drainage potential as determined by the above formula. The formation dip in Boulder varies from 1000'/mile to 1500'/mile. (See plat following and Appendix III).


PRESSURE PRODUCTION HISTORY
BOULDER MANCOS POOL
RIO ARRIBA COUNTY
LEGEND
Standard of Texas 4-26 #2,3,4 (datum +3300')
Mobil #12-14 (datum +3300')
Mobil #23-14 (datum +3300')
Standard of Texas 4-26 #5 (Gas Well) Sept. 1962
measured BHP at 3600' depth
Remaining pressures estimated for 3600'
depth from surface pressures
Locus of estimated average pressure at + 3300'
Gas — Oil Ratio
BOTTOM HOLE PRESSURE - PSIG
AVERAGE GAS - OIL RATIO - MCF/BBL
CUMULATIVE PRODUCTION - HUNDREDS OF THOUSANDS OF BARRELS
1-1-62
3-1-62
8-4-62
9-1-62
10-1-62
11-1-62
1-1-63
2-1-63
3-1-63
4-1-63
5-1-63
1-1-64
2-1-64
6-13-65
5-30-66

BOULDER MANCOS



The Boulder Pool was well positioned to obtain gravity drainage recoveries: steep dip, short distance downdip, high transmissibility and crestal gas cap. (Reference Appendix - Part III).

BOULDER MANCOS POOL
COMPARISON OF OIL PRODUCTION RATES
WITH
GRAVITY DRAINAGE POTENTIAL

Gravity drainage potential = BOPD/linear mile along strike = $\frac{2580 \ Koh \ d \sin \theta}{u_o \ B_t}$

Reservoir Temperature 140° F
Dip 1250'/Mile

Date (1)	Press. (Psia) (2)	Z (3)	S.G.* Oil (4)	S.G.* Gas (5)	d = S.G. Oil Minus S.G. Gas (6)	Vis (cp) (7)	Res. Bbls. Per MCF (8)	GOR (9)	Total Res. Bbl. Per Stock Tank Bbl (10)	Field Oil Prod. Bbls/Mo. (11)	Field Oil Prod. Rate** (12)	Gravity Drainage Rate for Koh: 10 d-ft (13)	20 d-ft (14)	30 d-ft (15)
3-01-62	930	.88	.82	.05	.77	3.1	2.91	300	1.54	13,000	108	1000	2000	3000
5-01-63	750	.90	.82	.04	.78	3.1	3.70	650	2.95	36,000	300	500	1000	1500
2-01-64	590	.92	.82	.03	.79	3.3	4.81	1400	7.33	36,000	300	200	400	600
6-13-65	200	.97	.82	.01	.81	4.2	14.9	4000	60	13,000	108	20	40	60***
1970	est 100	.98	.82	-	.82	4.5	30	300	10	5,400	45	100	200	300

* Specific gravity (water = 1.0)

** BOPD per linear mile along strike

*** Peak GOR

Reservoir fluid properties from bottom hole sample analysis (Appendix Part I).

CANADA OJITOS UNIT

Initial development in Canada Ojitos Unit was concurrent with Boulder. It was recognized that Boulder oil recoveries were substantially through gravity drainage; and investigation was made to determine if Canada Ojitos Unit production might also receive this high gravity drainage recovery.

For the Canada Ojitos Unit oil characteristics, dip of 200' to 400' per mile and measured transmissibility (Koh) of 5 to 10 darcy feet (by interference tests) it was determined that the gravity drainage potential was in the range of 400 to 800 BOPD per linear mile along the strike.

This was not as high as Boulder but high enough for commercial operation of the reservoir providing it was not overdrilled. One of the problems was the 5 to 6 mile downdip section below the gas-oil contact, meaning that the 400 to 800 BOPD must be shared by wells in a 5 or 6 square mile section of the reservoir. Also unless pressure was maintained, the gravity drainage rate would decrease as pressure declined and free gas developed.

If produced by solution gas drive the poor relative permeability characteristics would mean an exceptionally low recovery; and the depletion mechanism would deteriorate to solution gas drive unless the withdrawal rates were kept low and pressure maintained.

On the next two pages are schedule and graph showing gravity drainage potential if the producing mechanism is primarily solution gas drive and the pressures and GOR's are typical for fractured formations. Note that the potential commences at about 800 barrels per day per linear mile along the strike but drops rapidly to less than 200 and is negligible when the GOR reaches 8,000 to 10,000. Accordingly it is clear that if the producing mechanism be allowed to deteriorate to that of solution gas drive that the gravity drainage share will be rather small.

POTENTIAL GRAVITY DRAINAGE RATES
CANADA OJITOS UNIT

Gravity drainage potential = BOPD/linear mile along strike = $\frac{2580\ Koh\ d \sin \theta}{u_o\ B_t}$ Dip 200'/Mile

TABLE A - FOR TYPICAL PRESSURE AND GAS-OIL RATIOS UNDER SOLUTION GAS DRIVE

Press. (Psia) (2)	Z (3)	S.G.* Oil (4)	S.G.* Gas (5)	d - S.G. Oil Minus S.G. Gas (6)	Vis (cp) (7)	Res. Bbls. Per MCF (8)	GOR (9)	Total Reservoir Bbls per Stock Tank Bbl (BT) (10)	Gravity Drainage Rate *** for Koh = 10 darcy feet (11)
930	.88	.82	.05	.77	3.1	2.91	300	1.54	1000
1500	.85	.72	.085	.635	.62	1.83	500	1.30	700
1450	.85	.72	.082	.638	.63	1.90	1500	4.13	240
1400	.855	.72	.079	.641	.64	1.98	2500	5.26	190
1300	.860	.72	.079	.647	.67	2.14	4000	8.78	110
1000	.890	.73	.054	.676	.76	2.88	8000	23	38
700	.895	.74	.045	.695	.88	4.14	14000	58	13

TABLE B - FOR OTHER CONDITIONS

Press. (Psia) (2)	Z (3)	S.G.* Oil (4)	S.G.* Gas (5)	d - S.G. Oil Minus S.G. Gas (6)	Vis (cp) (7)	Res. Bbls. Per MCF (8)	GOR (9)	Total Reservoir Bbls per Stock Tank Bbl (BT) (10)	Gravity Drainage Rate *** for Koh = 10 darcy feet (11)
1500	.85	.72	.085	.635	.62	1.83	600	1.48	675
1500	.85	.72	.085	.635	.62	1.83	800	1.85	540
1000	.89	.73	.054	.76	.76	2.88	600	1.97	440
1000	.89	.73	.054	.76	.76	2.88	800	2.55	340

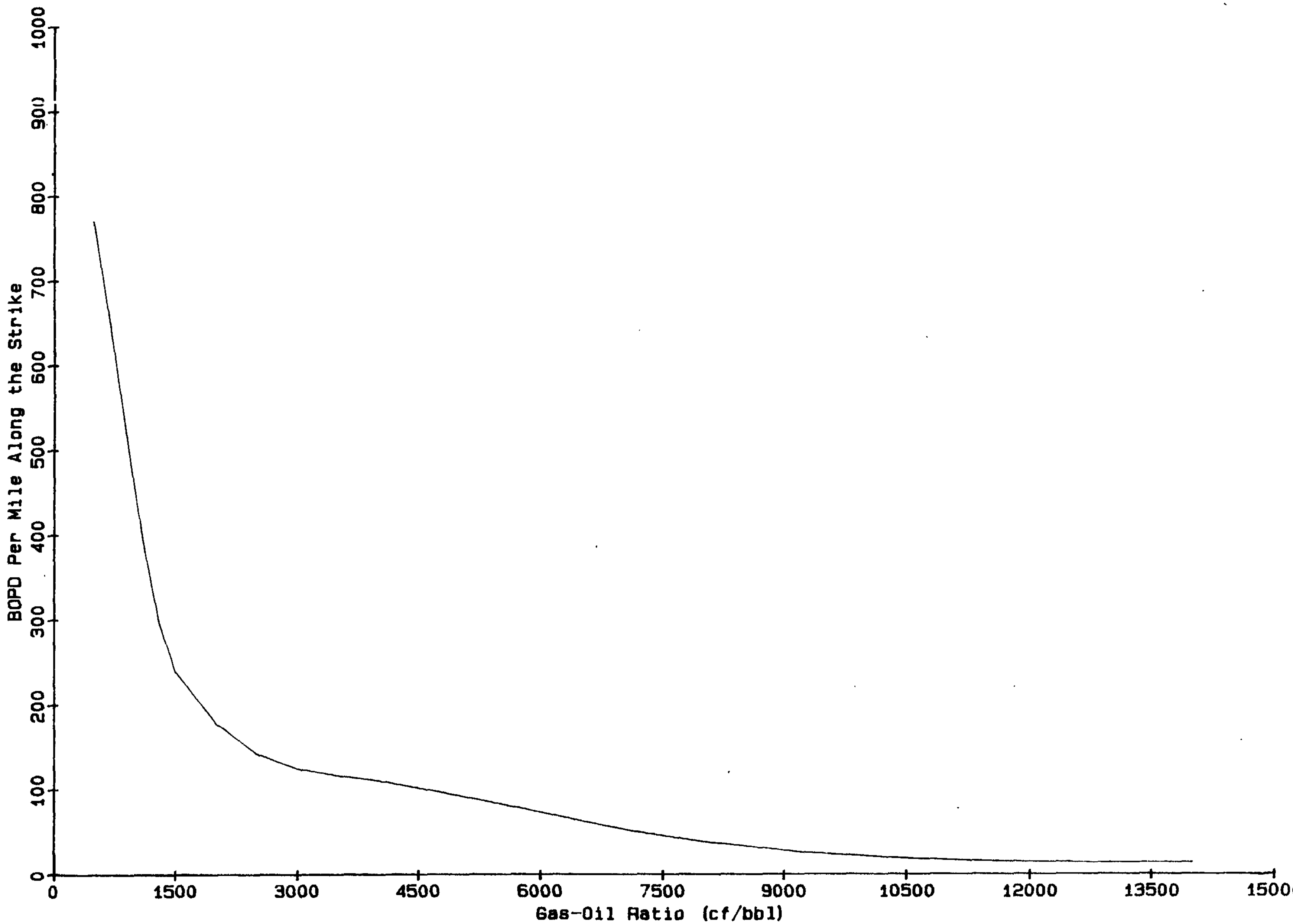
* Specific gravity (water = 1.0)

** BOPD per linear mile along strike

Reservoir fluid properties from bottom hole sample analysis (Appendix Part II).

COU GRAVITY DRAINAGE POTENTIAL

For Koh = 10 darcy feet
Dip = 200 feet per mile
Basic Depletion: S.G.D.

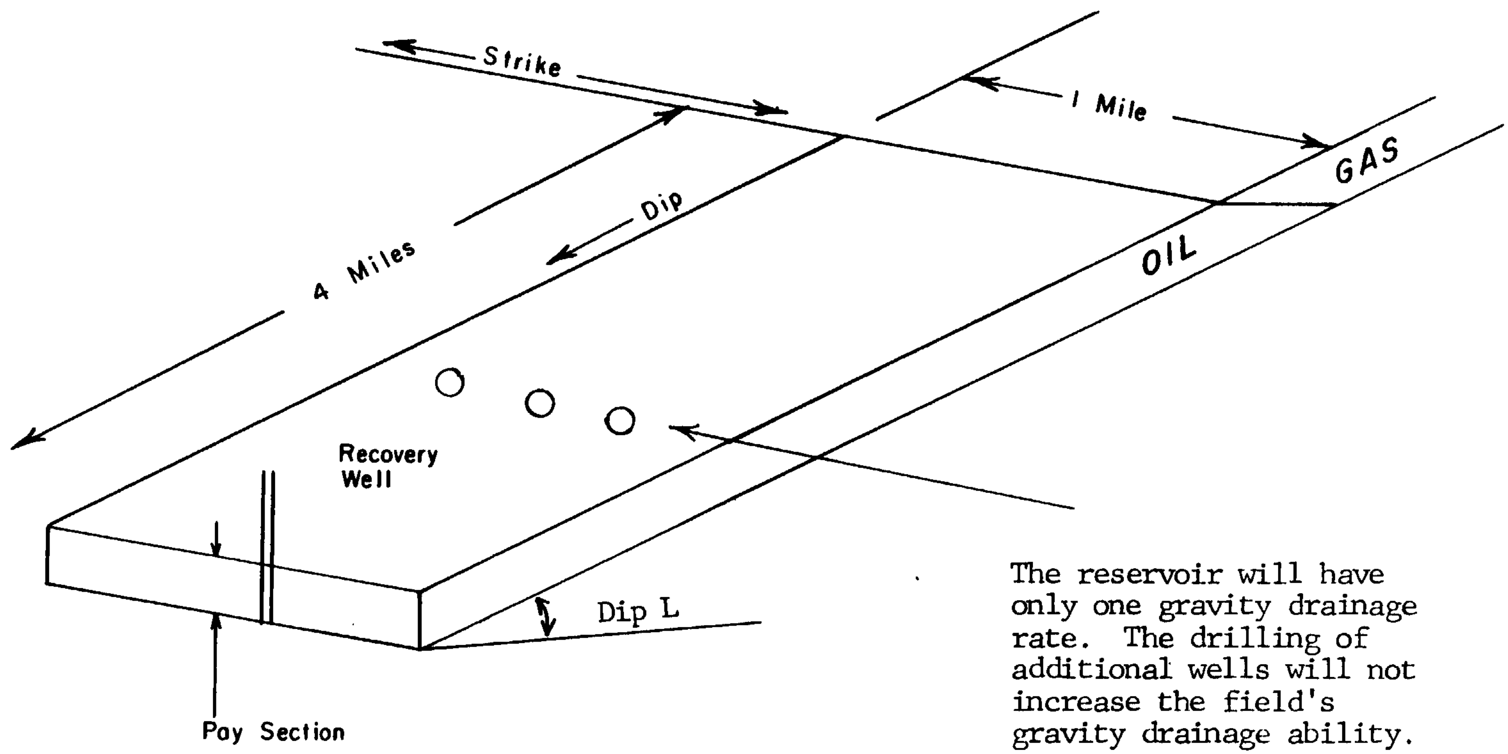


THERE IS ONLY ONE GRAVITY DRAINAGE RATE AVAILABLE FOR A TYPICAL SECTION OF THE RESERVOIR

The sketch on the facing page illustrates this fact of gravity drainage.

Note that if a well has the ability to produce the gravity drainage potential of a one mile wide section of the reservoir, that the drilling of additional wells will not increase the reservoir gravity drainage ability; but in fact if they are produced in addition to the initial well they will serve to reduce the ultimate recovery by causing the producing mechanism to deteriorate to that of solution gas drive.

SCHEMATIC GRAVITY DRAINAGE SYSTEM
(Fracture Blocks Omitted)



The reservoir will have only one gravity drainage rate. The drilling of additional wells will not increase the field's gravity drainage ability.

HISTORY OF GRAVITY DRAINAGE
CANADA OJITOS UNIT

The Canada Ojitos Unit has produced efficiently under the gravity drainage mechanism several million barrels of oil. That this is a fact is attested to by the low GOR's of the recovery wells while the reservoir has been operated under pressure maintenance by gas injection.

If gravity drainage were not operative, then the producing mechanism under gas injection would be simply that of "gas drive"; and under gas drive without gravity segregation, the low viscosity of the gas would cause it to permeate the reservoir, in accordance with the fractional flow relations, with early high GOR's (Reference 4, and others).

Any oil "bypassed" during the first gravity drainage phase of high pressure gravity drainage depletion will be recovered later during low pressures (Reference 4).

When the above facts are recognized, two important characteristics of this reservoir are evident:

1. A large proportion of the reservoir volume is in high capacity fractures (otherwise the injected gas would have displaced the small fracture volume early in the producing life).

2. Gravity segregation has been significant (even with the large volume in the fracture system, injected gas, if operating only under "gas drive" would have caused early high GOR's).

APPENDIX

Part I: Reservoir Fluid Analysis Boulder Pool (pink).

Part II: Reservoir Fluid Analysis Canada Ojitos Unit (green).

Part III: Oil and Gas Fields of the Four Corners Area, Four Corners Geological Society, Volume I, Pages 248-250, 1978 (blue).

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

October 23, 1962

RESERVOIR FLUID DIVISION

Standard Oil Company of Texas
Drawer S
Monahans, Texas

Subject: Reservoir Fluid Study
Jicarilla 4-26 No. 3 Well
Boulder Mancos Field
Rio Arriba County, New Mexico
Our File Number: RFL 2301

Gentlemen:

Subsurface fluid samples were collected from the subject well by a representative of Core Laboratories, Inc. and submitted to our Dallas laboratory for use in a reservoir fluid study. The results of this study are presented on the following pages.

The saturation pressure of the fluid was measured to be 802 psig at the reservoir temperature of 141° F. The reservoir pressure at the sampling depth is 856 psig.

During differential pressure depletion the fluid evolved 147 standard cubic feet of gas per barrel of residual oil. The associated formation volume factor was measured to be 1.098 barrels of saturated fluid per barrel of residual oil. The viscosity of the fluid was measured under similar depletion conditions. It varied from a minimum of 3.03 centipoises at the saturation pressure to a maximum of 5.44 centipoises at atmospheric pressure.

It was a pleasure to perform this study for you. If you have any questions or if we may assist you further, please do not hesitate to contact us.

Very truly yours,

Core Laboratories, Inc.
Reservoir Fluid Division
P. L. Moses

A. C. Carnes, Jr.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2301

Company	Standard Oil Company of Texas	Date Sampled	October 4, 1962
Well	Jicarilla 4-26 No. 3	County	Rio Arriba
Field	Boulder Mancos	State	New Mexico

FORMATION CHARACTERISTICS

Formation Name	Gallup
Date First Well Completed	August, 1960
Original Reservoir Pressure	867 PSIG @ 3880 Ft.
Original Produced Gas-Oil Ratio	167 SCF/Bbl
Production Rate	175 Bbl/Day
Separator Pressure and Temperature	PSIG, °F.
Oil Gravity at 60° F.	32.5 °API
Datum	Ft. Subsea
Original Gas Cap	

WELL CHARACTERISTICS

Elevation	7240 GL Ft.
Total Depth	4120 Ft.
Producing Interval	3820-4120 Ft.
Tubing Size and Depth	In. to Ft.
Productivity Index	Bbl/D/PSI @ Bbl/Day
Last Reservoir Pressure	867 PSIG @ 3880 Ft.
Date	October 4, 1962
Reservoir Temperature	139* °F. @ 3880 Ft.
Status of Well	Shut in 65 hours
Pressure Gauge	Amerada (DO)
Normal Production Rate	175 Bbl/Day
Gas-Oil Ratio	200 SCF/Bbl
Separator Pressure and Temperature	PSIG, °F.
Base Pressure	15.025 PSIA
Well Making Water	None % Cut

SAMPLING CONDITIONS

Sampled at	3850 Ft.
Status of Well	Shut in 65 hours
Gas-Oil Ratio	SCF/Bbl
Separator Pressure and Temperature	PSIG, °F.
Tubing Pressure	4 PSIG
Casing Pressure	PSIG
Core Laboratories Engineer	NT
Type Sampler	Perco

REMARKS:

* Temperature extrapolated to mid-point of producing interval = 141° F.

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File RFL 2301
Well Jicarilla 4-26 No. 3

STANDARD of TEXAS
BOULDER P[illegible]

VOLUMETRIC DATA OF Reservoir Fluid SAMPLE

1. Saturation pressure (bubble-point pressure) 802 PSIG @ 141 °F.
2. Thermal expansion of saturated oil @ 5000 PSI = $\frac{V @ 141\ °F}{V @ 76\ °F}$ = 1.02778
3. Compressibility of saturated oil @ reservoir temperature: Vol/Vol/PSI:

   From 5000 PSI to 3500 PSI = 5.27×10^{-6}

   From 3500 PSI to 2000 PSI = 5.92×10^{-6}

   From 2000 PSI to 802 PSI = 6.63×10^{-6}
4. Specific volume at saturation pressure: ft ^{3}/lb 0.01959 @ 141 °F.

$\frac{1}{.01959} = 51.05$ #/ft^3

→ .3545 #/in^2/ft

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DALLAS, TEXAS

File RFL 2301
Well Jicarilla 4-26 No. 3

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 141 °F., RELATIVE VOLUME OF OIL AND GAS, V/Vsat.	VISCOSITY OF OIL @ 141 °F., CENTIPOISES	DIFFERENTIAL LIBERATION @ 141 °F.		
			GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/VR
5010		4.52			
5000	0.9755				1.071
4505		4.33			
4500	0.9780				1.074
4000	0.9806	4.15			1.077
3500	0.9833	3.96			1.080
3010		3.75			
3000	0.9861				1.083
2510		3.60			
2500	0.9890				1.086
2005		3.42			
2000	0.9921				1.089
1505		3.26			
1500	0.9953				1.093
1400	0.9960				1.094
1300	0.9967				1.094
1200	0.9973				1.095
1100	0.9980				1.096
1015		3.10			
1000	0.9987				1.097
900	0.9994				1.097
802	1.0000	3.03	0	147	1.098
798	1.0016				
794	1.0032				
790	1.0062				
777	1.0139				
755		3.09			
751	1.0293				
712	1.0477				
698			19	128	1.092
663	1.0795				
655		3.20			
603	1.1268				

V = Volume at given pressure
Vsat. = Volume at saturation pressure and the specified temperature.
VR = Residual oil volume at 14.7 PSI absolute and 60° F.

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DALLAS, TEXAS

File RFL 2301
Well Jicarilla 4-26 No. 3

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 141 °F., RELATIVE VOLUME OF OIL AND GAS, V/VSAT.	VISCOSITY OF OIL @ 141 °F., CENTIPOISES	DIFFERENTIAL LIBERATION @ 141 °F.: GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/VR
601			34	113	1.087
550		3.37			
538	1.1915				
499			50	97	1.081
473	1.2765				
455		3.52			
404	1.3966				
398			67	80	1.075
350		3.78			
342	1.5473				
300			83	64	1.069
276	1.7859				
250		4.06			
200	2.2504				
199			100	47	1.062
150		4.38			
138	3.0146				
98			119	28	1.055
50		4.82			
0		5.44	147	0	1.036
				@ 60° F. =	1.000

Gravity of residual oil = 30.5° API @ 60° F.

V = Volume at given pressure
VSAT. = Volume at saturation pressure and the specified temperature.
VR = Residual oil volume at 14.7 PSI absolute and 60° F.

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Well Jicarilla 4-26 No. 3

Differential Pressure Depletion at 141° F.

Pressure PSIG	Oil Density Gms/Cc	Gas Gravity	Deviation Factor Z
802	0.8176		
698	0.8199	0.686	0.934
601	0.8218	0.687	0.940
499	0.8242	0.689	0.950
398	0.8265	0.699	0.958
300	0.8287	0.714	0.968
199	0.8314	0.743	0.979
98	0.8340	0.806	
0.	0.8428	1.093	

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File RFL 2301

Well Jicarilla 4-26 No. 3

SEPARATOR TESTS OF Reservoir Fluid SAMPLE

SEPARATOR PRESSURE, PSI GAUGE	SEPARATOR TEMPERATURE, ° F	SEPARATOR GAS/OIL RATIO See Foot Note (1)	STOCK TANK GAS/OIL RATIO See Foot Note (1)	STOCK TANK GRAVITY, ° API @ 60° F.	SHRINKAGE FACTOR, $V_R/V_{SAT.}$ See Foot Note (2)	FORMATION VOLUME FACTOR, $V_{SAT.}/V_R$ See Foot Note (3)	SPECIFIC GRAVITY OF FLASHED GAS
0	74	155		30.5	0.9033	1.107	0.885
30	74	138	10	30.7	0.9102	1.099	
60	74	127	20	30.7	0.9099	1.099	
120	74	111	40	30.7	0.9074	1.102	

(1) Separator and Stock Tank Gas/Oil Ratio in cubic feet of gas @ 60° F. and 14.7 PSI absolute per barrel of stock tank oil @ 60° F.

(2) Shrinkage Factor: $V_R/V_{SAT.}$ is barrels of stock tank oil @ 60° F. per barrel of saturated oil @ 802 PSI gauge and 141 ° F.

(3) Formation Volume Factor: $V_{SAT.}/V_R$ is barrels of saturated oil @ 802 PSI gauge and 141 ° F. per barrel of stock tank oil @ 60° F.

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DALLAS, TEXAS

File RFL 2301

Company Standard Oil Company of Texas Formation Gallup

Well Jicarilla 4-26 No. 3 County Rio Arriba

Field Boulder Mancos State New Mexico

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	WEIGHT PER CENT	MOL PER CENT	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Hydrogen Sulfide					
Carbon Dioxide	0.33	1.50			
Nitrogen	0.04	0.26			
Methane	1.38	17.21			
Ethane	0.63	4.17			
Propane	0.22	0.97			
iso-Butane	0.10	0.35			
n-Butane	0.11	0.37			
iso-Pentane	0.31	0.86			
n-Pentane	0.45	1.25			
Hexanes	0.97	2.25			
Heptanes plus	95.46	70.81	0.8771	29.7	269
	100.00	100.00			

Core Laboratories, Inc.
Reservoir Fluid Division

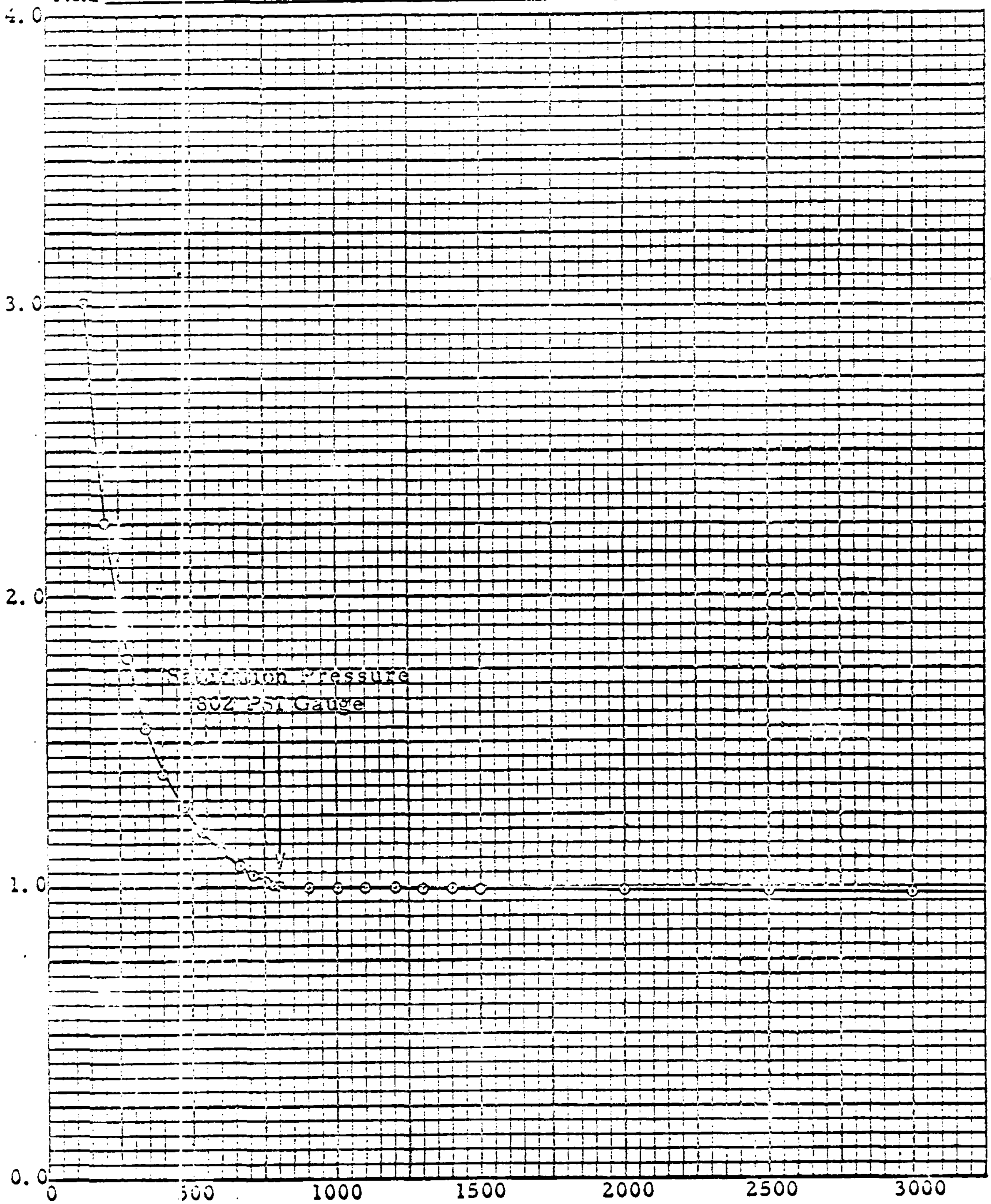
A. C. Carnes, Jr.

A. C. Carnes, Jr.
Senior Engineer

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

PRESSURE-VOLUME RELATIONS OF RESERVOIR FLUID

Company Standard Oil Co. of Texas
Formation Gallup
Well Jicarilla 4-26 No. 3
County Rio Arriba
Field Boulder Mancos
State New Mexico



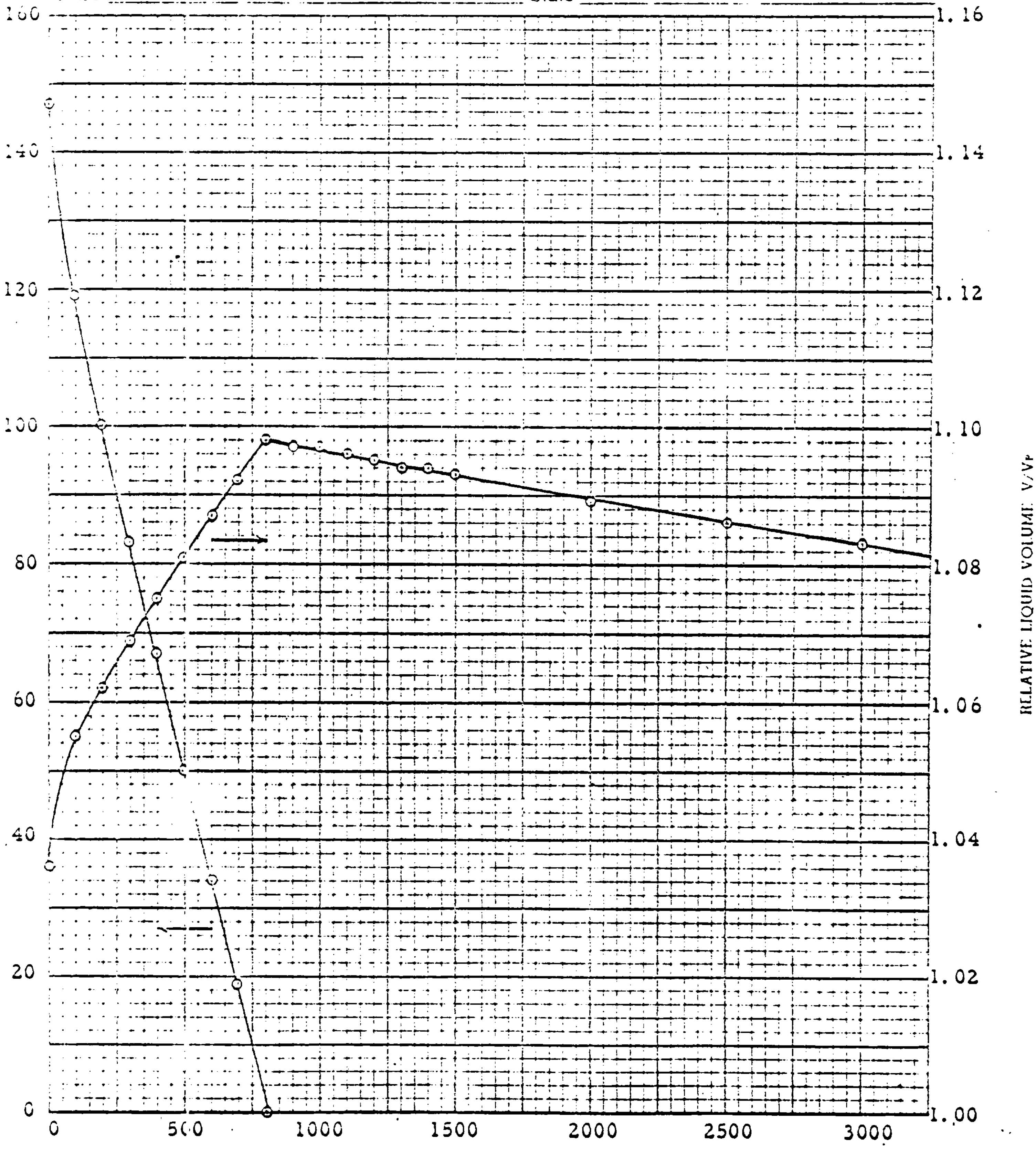
PRESSURE: POUNDS PER SQUARE INCH GAUGE

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2301

DIFFERENTIAL VAPORIZATION OF RESERVOIR FLUID

Company Standard Oil Co. of Texas — Formation Gallup
Well Jicarilla 4-26 No. 3 — County Rio Arriba
Field Boulder Mancos — State New Mexico



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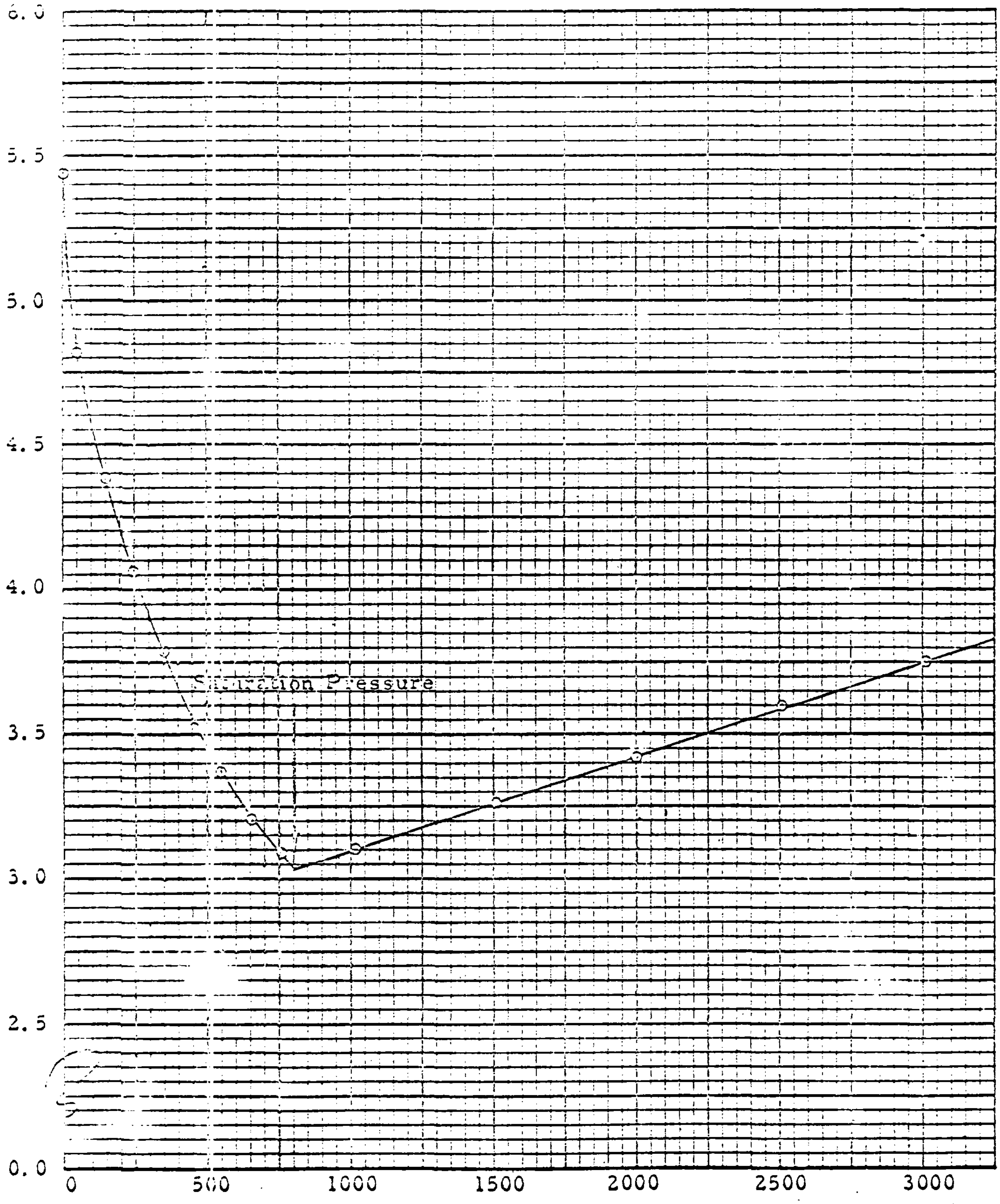
DALLAS, TEXAS

Viscosity of Reservoir Fluid

Company Standard Oil Co. of Texas — Formation Gallup
Well Jicarilla 4-26 No. 3 — County Rio Arriba
Field Boulder Mancos — State New Mexico



Pressure: PSIG

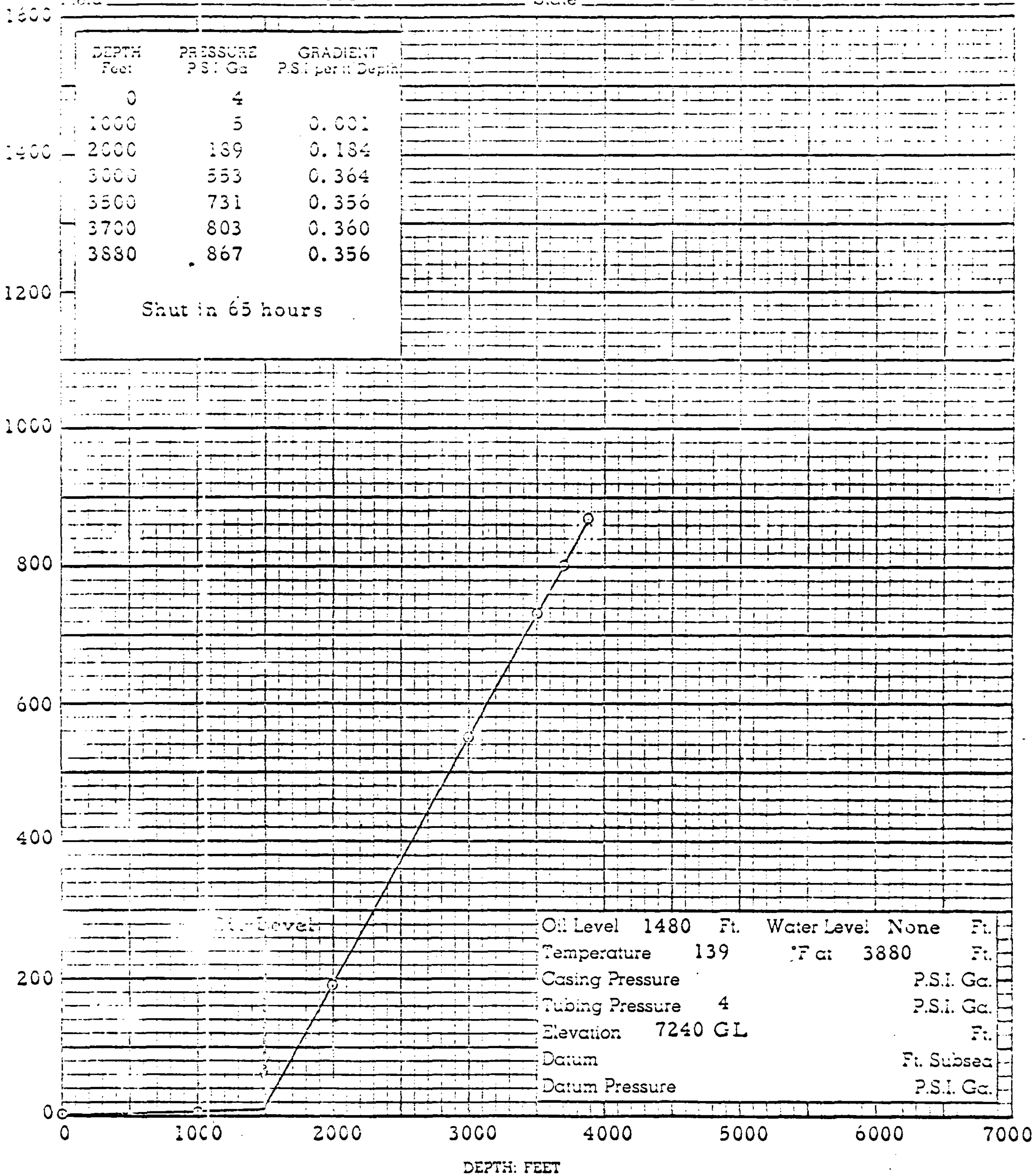
CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 2301

Company Standard Oil Co. of Texas
Well Jicarilla 4-26 No. 3
Field Boulder Mancos
Formation Gallup
County Rio Arriba
State New Mexico

DEPTH Feet	PRESSURE P.S.I. Ga.	GRADIENT P.S.I. per ft Depth
0	4	
1000	5	0.001
2000	189	0.184
3000	553	0.364
3500	731	0.356
3700	803	0.360
3880	867	0.356

Shut in 65 hours



Oil Level 1480 Ft. Water Level None Ft.
Temperature 139 °F at 3880 Ft.
Casing Pressure P.S.I. Ga.
Tubing Pressure 4 P.S.I. Ga.
Elevation 7240 GL Ft.
Datum Ft. Subsea
Datum Pressure P.S.I. Ga.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

July 27, 1965

RESERVOIR FLUID DIVISION

Benson-Montin-Greer Drilling Corporation
158 Petroleum Center Building
Farmington, New Mexico

Attention: Mr. Albert R. Greer

SE¼ 11

Subject: Reservoir Fluid Study
Bolack-Greer Inc. L-11 25N-1W
Canada Ojitos Unit No. 12-11 Well
Puerto Chiquito Field
Rio Arriba County, New Mexico
Our File Number: RFL 3366

Gentlemen:

Subsurface fluid samples were collected from the subject well by a representative of Core Laboratories, Inc. and were delivered to our laboratory in Dallas for use in a reservoir fluid study. The results of this study are presented on the following pages.

The saturation pressure of the fluid was found to be 1519 psig at the reservoir temperature of 162° F. The associated formation volume factor was found to be 1.297 barrels of saturated fluid per barrel of residual oil. By differential pressure depletion the fluid evolved 478 standard cubic feet of gas per barrel of residual oil. Under similar depletion conditions the viscosity increased from a minimum of 0.625 centipoise at the saturation pressure to a maximum of 1.704 centipoises at atmospheric pressure. The saturation pressure of the fluid was measured at several different temperatures as you requested.

It has been a pleasure to perform this study for you. If you have any questions or if we may assist you further in any way, please do not hesitate to contact us.

Very truly yours,

Core Laboratories, Inc.
Reservoir Fluid Division

P. L. Moses (JB)

P. L. Moses
Operations Supervisor

PLM:JB:bjm
7 cc. - Addressee

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

Company	Benson-Montin-Greer Drilling Corporation	Date Sampled	July 1, 1965
Well	Canada Ojitos Unit No. 12-11	County	Rio Arriba
Field	Puerto Chiquito	State	New Mexico

FORMATION CHARACTERISTICS

Formation Name	Nio Braro (Gallup)
Date First Well Completed	October, 1962
Original Reservoir Pressure	1631 PSIG @ 5957 Ft.
Original Produced Gas-Oil Ratio	SCF/Bbl
Production Rate	Bbl/Day
Separator Pressure and Temperature	None PSIG, °F.
Oil Gravity at 60° F.	°API
Datum	Ft. Subsea
Original Gas Cap	

WELL CHARACTERISTICS

Elevation	7232 KB Ft.
Total Depth	6687 Ft.
Producing Interval	6648-6687 Ft.
Tubing Size and Depth	In. to Ft.
Productivity Index	Bbl/D/PSI @ Bbl/Day
Last Reservoir Pressure	1693 PSIG @ 6650 Ft.
Date	July 1, 1965
Reservoir Temperature	162 °F. @ 6650 Ft.
Status of Well	Shut in 27 days
Pressure Gauge	Amerada
Normal Production Rate	Bbl/Day
Gas-Oil Ratio	SCF/Bbl
Separator Pressure and Temperature	PSIG, °F.
Base Pressure	15.025 PSIA
Well Making Water	None % Cut

SAMPLING CONDITIONS

Sampled at	6650 KB Ft.
Status of Well	Shut in 27 days
Gas-Oil Ratio	SCF/Bbl
Separator Pressure and Temperature	PSIG, °F.
Tubing Pressure	0 PSIG
Casing Pressure	0 PSIG
Core Laboratories Engineer	NT
Type Sampler	Perco

REMARKS:

CL-816

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366
Well Canada Ojitos Unit No. 12-11

VOLUMETRIC DATA OF Reservoir Fluid SAMPLE

1. Saturation pressure (bubble-point pressure) 1519 PSIG @ 162 °F.
2. Thermal expansion of saturated oil @ 5000 PSI $= \frac{V @ 162\ °F}{V @ 76\ °F} =$ 1.04528
3. Compressibility of saturated oil @ reservoir temperature: Vol/Vol/PSI:

   From 5000 PSI to 3500 PSI = 8.24×10^{-6}

   From 3500 PSI to 2500 PSI = 9.49×10^{-6}

   From 2500 PSI to 1519 PSI = 10.68×10^{-6}
4. Specific volume at saturation pressure: ft^3/lb 0.02218 @ 162 °F.
5. Saturation pressure at various temperatures:

Temperature, °F.	Saturation Pressure, PSI BHS No. 1	Saturation Pressure, PSI BHS No. 2
76	1203	1204
110	1351	
152	1491	1492
162	1519	1519
172	1540	

$.02218\ ft^3/\#$ $\qquad \frac{1}{(.02218)(144)} = .313\ \#/in^2/ft$

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366
Well Canada Ojitos Unit
No. 12-11

Reservoir Fluid SAMPLE TABULAR DATA

PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 162 °F. RELATIVE VOLUME OF OIL AND GAS, V/VSAT.		VISCOSITY OF OIL @ 162 °F. CENTIPOISES	DIFFERENTIAL LIBERATION @ 162 °F. GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/VR
1514 5000	0.9680		0.841			1.256
4500	0.9718					1.260
4000	0.9759		0.781			1.266
3500	0.9801		0.751			1.271
3000	0.9847		0.719			1.277
2500	0.9895		0.686			1.283
2300	0.9916					1.286
2100	0.9936					1.289
2000	0.9947		0.652			1.290
1900	0.9957					1.291
1800	0.9968					1.293
1700	0.9981					1.294
1600	0.9991					1.296
1533 1519	1.0000	.313	0.625	0	478	1.297
1508	1.0028					
1498	1.0054					
1481	1.0101					
1457	1.0162					
1429	1.0254					
1389				32	446	1.284
1369	1.0458	.299				
1350			0.684			
1288	1.0766	.291				
1259				65	413	1.270
1250			0.696			
1196	1.1174	.280				
1129				96	382	1.257
1100			0.731			
1098 1084	1.1789	.265				
968	1.2610	.248				
963				136	342	1.239
950			0.780			
858	1.3638	.230				
812				173	305	1.224

V = Volume at given pressure
VSAT. = Volume at saturation pressure and the specified temperature.
VR = Residual oil volume at 14.7 PSI absolute and 60° F.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366
Well Canada Ojitos Unit
No. 12-11

Reservoir Fluid SAMPLE TABULAR DATA

	PRESSURE PSI GAUGE	PRESSURE-VOLUME RELATION @ 162 °F., RELATIVE VOLUME OF OIL AND GAS, V/Vsat.	DENSITY #/in 4,	VISCOSITY OF OIL @ 162 °F., CENTIPOISES	DIFFERENTIAL LIBERATION @ 162 °F. GAS/OIL RATIO LIBERATED PER BARREL OF RESIDUAL OIL	GAS/OIL RATIO IN SOLUTION PER BARREL OF RESIDUAL OIL	RELATIVE OIL VOLUME, V/VR
	800			0.835			
	750	1.4975	.209				
672	658				211	267	1.207
	657	1.6518	.194				
	650			0.900			
	566	1.8577	.168				
533	519				246	232	1.192
	500			0.980			
	479	2.1482	.146				
	413	2.4573	.127				
373	359				287	191	1.175
	350	2.8694	.109				
	298	3.3145	.094				
	250	3.8813	.081	1.161			
232	218				328	150	1.156
122	108				367	111	1.133
14	0			1.704	478	0	1.049
						@ 60° F. =	1.000

Gravity of residual oil = 38.2° API @ 60° F.

V = Volume at given pressure
Vsat. = Volume at saturation pressure and the specified temperature.
VR = Residual oil volume at 14.7 PSI absolute and 60° F.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366
Well Canada Ojitos Unit No. 12-11

Differential Pressure Depletion at 162° F.

Pressure PSIG	Oil Density Gms/Cc	Gas Gravity	Deviation Factor Z
1519	0.7223		
1389	0.7258	0.696	0.882
1259	0.7298	0.698	0.887
1129	0.7336	0.701	0.894
963	0.7389	0.709	0.902
812	0.7438	0.718	0.914
658	0.7487	0.731	0.929
519	0.7534	0.753	0.943
359	0.7589	0.791	0.958
218	0.7642	0.886	0.976
108	0.7716	1.067	
0	0.7939	1.702	

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366
Well Canada Ojitos Unit No. 12-11

SEPARATOR TESTS OF Reservoir Fluid SAMPLE

SEPARATOR PRESSURE, PSI GAUGE	SEPARATOR TEMPERATURE, ° F.	SEPARATOR GAS/OIL RATIO See Foot Note (1)	STOCK TANK GAS/OIL RATIO See Foot Note (1)	STOCK TANK GRAVITY, ° API @ 60° F.	SHRINKAGE FACTOR, Vr/Vsat. See Foot Note (2)	FORMATION VOLUME FACTOR, Vsat./Vr See Foot Note (3)	SPECIFIC GRAVITY OF FLASHED GAS
0	74	483		38.1	0.7639	1.309	0.986
40	74	386	27	39.6	0.7943	1.259	
80	74	354	55	39.6	0.7968	1.255	
160	74	300	110	39.4	0.7943	1.259	

$110 \times \frac{14.7}{15.025} = 108$ cf/bbl

(1) Separator and Stock Tank Gas/Oil Ratio in cubic feet of gas @ 60° F. and 14.7 PSI absolute per barrel of stock tank oil @ 60° F.

(2) Shrinkage Factor: Vr/Vsat. is barrels of stock tank oil @ 60° F. per barrel of saturated oil @ 1519 PSI gauge and 162 ° F.

(3) Formation Volume Factor: Vsat./Vr is barrels of saturated oil @ 1519 PSI gauge and 162 ° F. per barrel of stock tank oil @ 60° F.

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

Company Benson-Montin-Greer Drilling Corporation
Formation Nio Braro (Gallup)

Well Canada Ojitos Unit No. 12-11
County Rio Arriba

Field Puerto Chiquito
State New Mexico

HYDROCARBON ANALYSIS OF Reservoir Fluid SAMPLE

COMPONENT	MOL PER CENT	WEIGHT PER CENT	DENSITY @ 60° F. GRAMS PER CUBIC CENTIMETER	° API @ 60° F.	MOLECULAR WEIGHT
Hydrogen Sulfide					
Carbon Dioxide	0.20	0.08			
Nitrogen	0.13	0.03			
Methane	26.36	3.65			
Ethane	6.86	1.78			
Propane	6.19	2.36			
iso-Butane	1.20	0.60			
n-Butane	4.29	2.15			
iso-Pentane	1.80	1.12			
n-Pentane	2.14	1.33			
Hexanes	4.49	3.34			
Heptanes plus	46.34	83.56	0.8474	35.3	209
	100.00	100.00			

Heptanes +

Core Laboratories, Inc.
Reservoir Fluid Division

P. L. Moses (B)

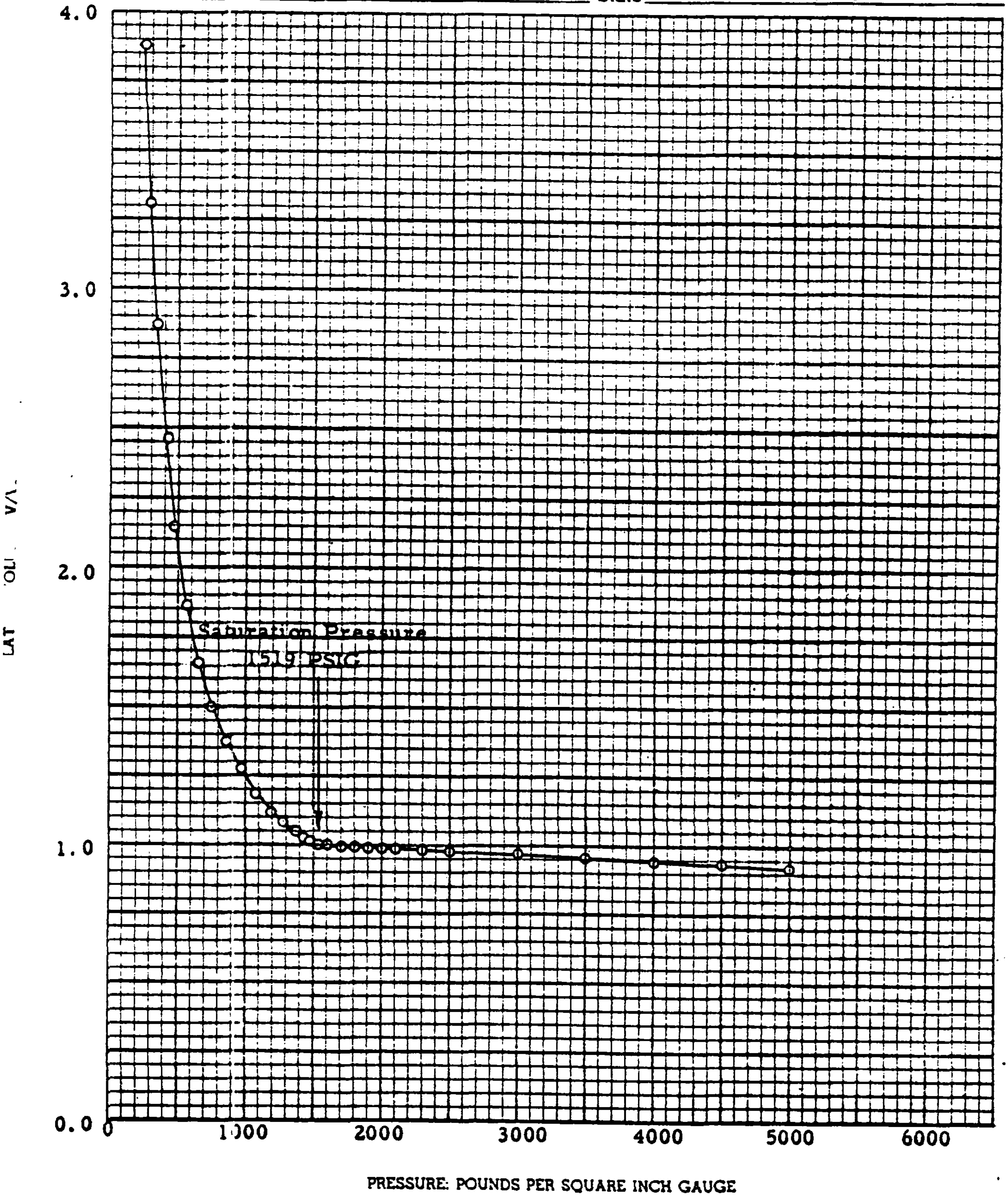
P. L. Moses
Operations Supervisor

CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

PRESSURE-VOLUME RELATIONS OF RESERVOIR FLUID

Company Benson-Montin-Greer Drilling Corporation
Formation Nio Braro (Gallup)
Well Canada Ojitos Unit No. 12-11
County Rio Arriba
Field Puerto Chiquito
State New Mexico

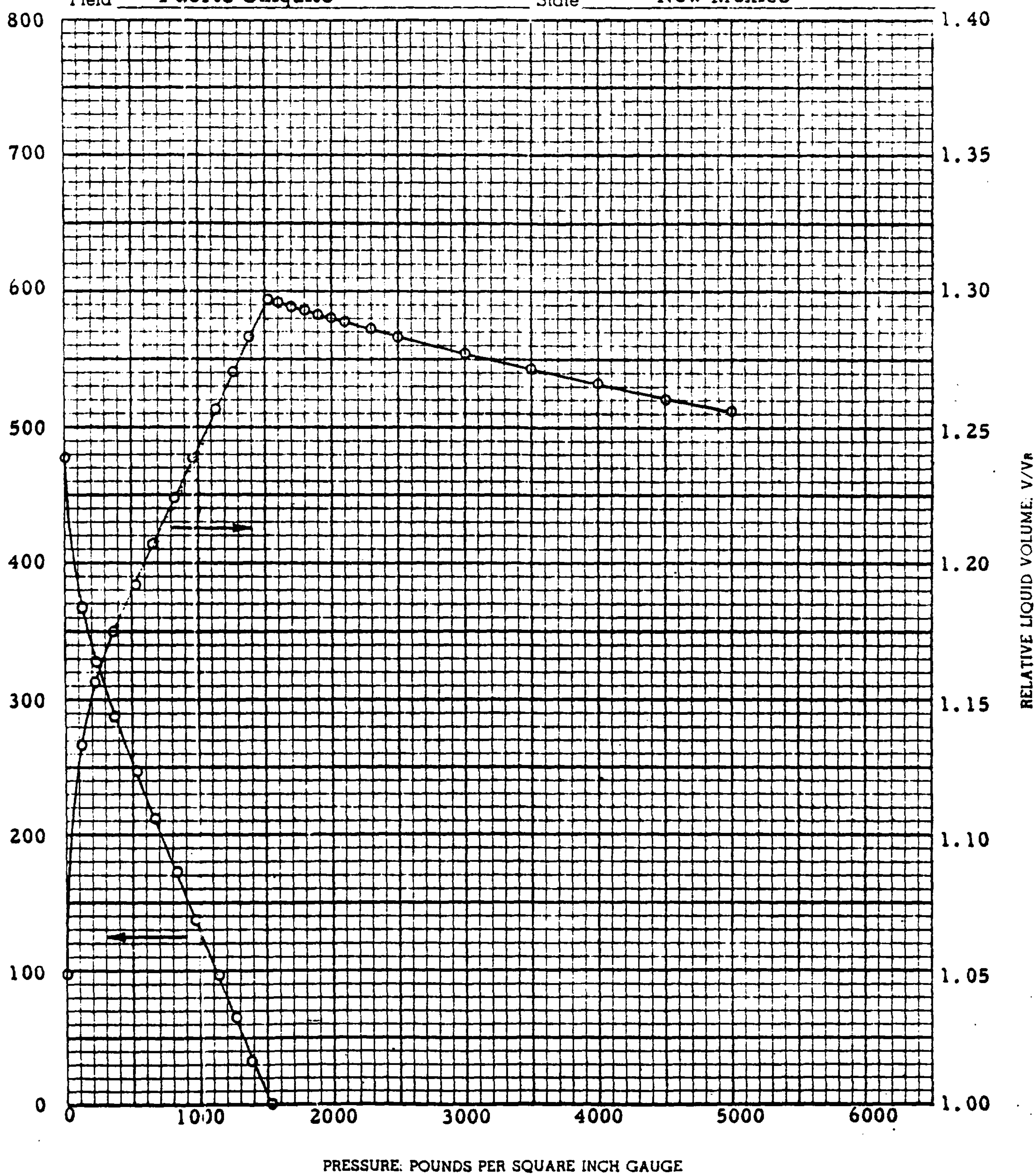


CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

DIFFERENTIAL VAPORIZATION OF RESERVOIR FLUID

Company Benson-Montin-Greer Drilling Corporation
Formation Nio Braro (Gallup)
Well Canada Ojitos Unit No. 12-11
County Rio Arriba
Field Puerto Chiquito
State New Mexico



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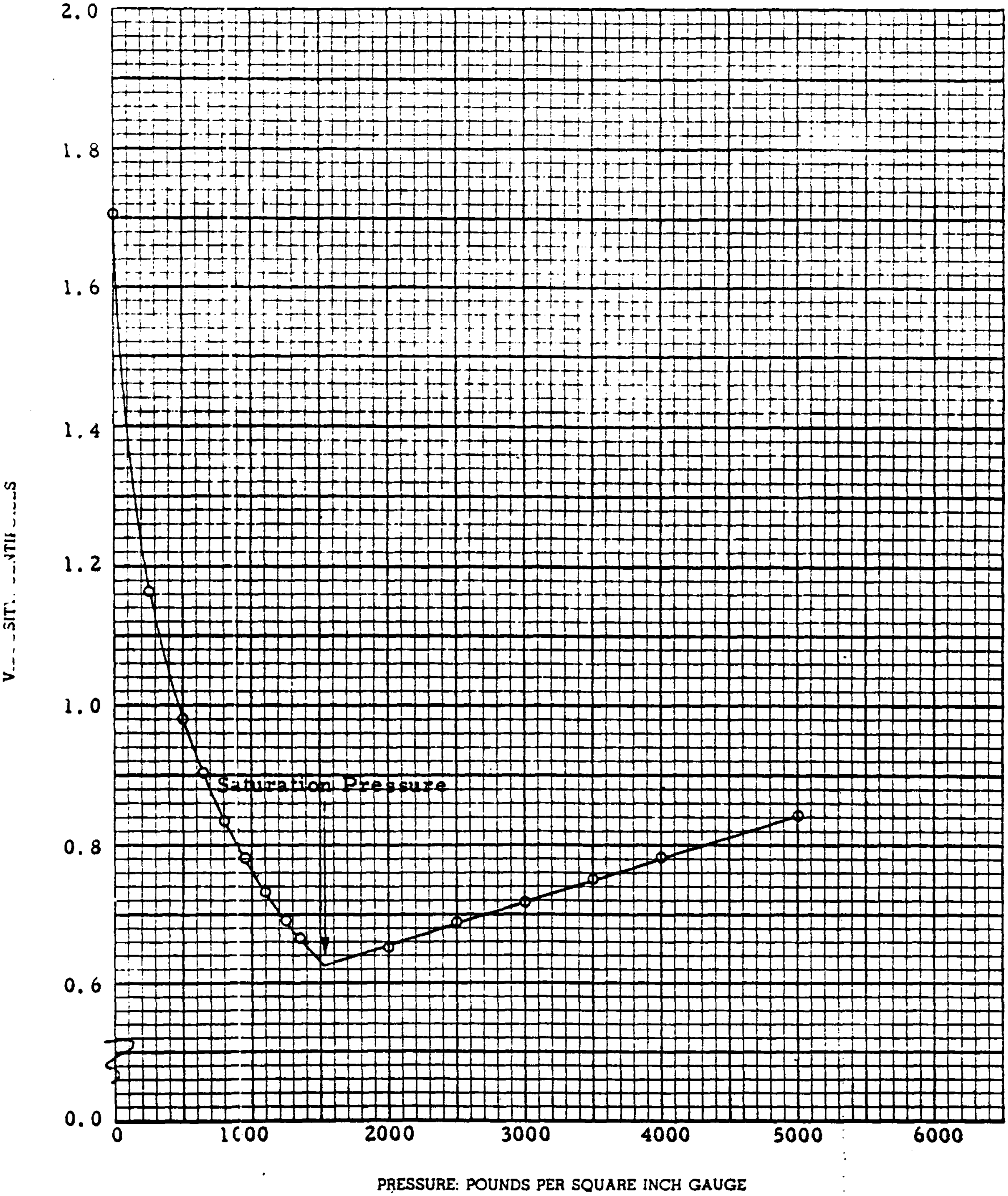
Petroleum Reservoir Engineering
DALLAS, TEXAS

VISCOSITY OF RESERVOIR FLUID

Company Benson-Montin-Greer Drilling Corporation
Formation Nio Braro (Gallup)
Well Canada Ojitos Unit No. 12-11
County Rio Arriba
Field Puerto Chiquito
State New Mexico



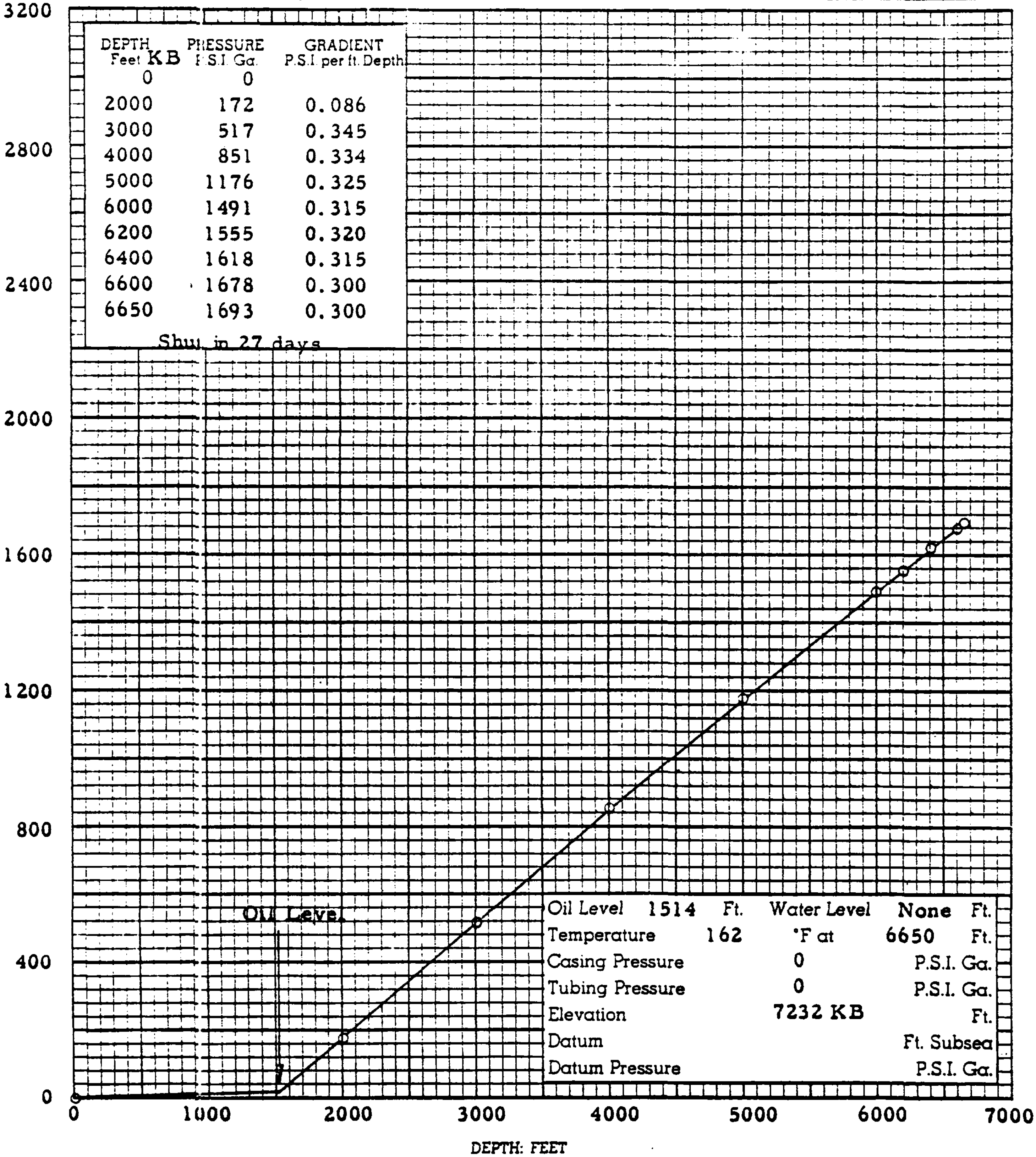
CORE LABORATORIES, INC.
Petroleum Reservoir Engineering
DALLAS, TEXAS

File RFL 3366

Company: Benson-Montin-Greer Drilling Corporation
Well: Canada Ojitos Unit No. 12-11
Field: Puerto Chiquito
Formation: Nio Braro (Gallup)
County: Rio Arriba
State: New Mexico

DEPTH Feet KB	PRESSURE P.S.I. Ga.	GRADIENT P.S.I. per ft. Depth
0	0	
2000	172	0.086
3000	517	0.345
4000	851	0.334
5000	1176	0.325
6000	1491	0.315
6200	1555	0.320
6400	1618	0.315
6600	1678	0.300
6650	1693	0.300

Shut in 27 days



Oil Level	1514 Ft.	Water Level	None	Ft.
Temperature	162	°F at	6650	Ft.
Casing Pressure		0		P.S.I. Ga.
Tubing Pressure		0		P.S.I. Ga.
Elevation		7232 KB		Ft.
Datum				Ft. Subsea
Datum Pressure				P.S.I. Ga.

BOULDER MANCOS
(Oil)
T. 28 N., R. 1 W., NMPM
Rio Arriba County, New Mexico

By: C. N. Needham
Mobil Oil Corporation

GEOLOGY

Regional Setting: East flank, San Juan Basin

Surface Formations: Cretaceous, Lewis Shale; Tertiary- Cretaceous, Animas Formation; and Tertiary, San Jose Formation

Exploration Method Leading to Discovery: Probably subsurface

Type of Trap: Fractured shale on a monocline

Producing Formation: Cretaceous, Mancos Shale

Gross Thickness and Lithology of Reservoir Rocks: See field commentary

Geometry of Reservoir Rock: See field commentary

Other Significant Shows: None

Oldest Stratigraphic Horizon Penetrated: Cretaceous, Mancos Shale

DISCOVERY WELL

Name: P-M Drilling Co. No. 1 Bayless

Location: NE NE (330' FNL and 330' FEL), sec. 15, T. 28 N., R. 1 W.

Elevation (KB): 7,427 feet

Date of Completion: May 15, 1961; plugging approved in 1965

Total Depth: 4,429 feet

Production Casing: 4½" at 4,150 feet cemented with 50 sacks of cement

Perforations: Open hole 4,150 feet to 4,429 feet

Stimulation: Sand-oil fracture with 42,000 gallons of oil and 20,000 lbs. of 20/40 sand; treating pressure 2,500 lbs. Injection rate 33 barrels per minute

Initial Potential: Pump 35 BOD

Bottom Hole Pressure: Unknown

DRILLING AND COMPLETION PRACTICES

Set 8 5/8" to 10¾" casing at approximately 130 feet with 100 sacks of cement; drill with gel-type mud to about 600 feet above pay, set 5½" to 7½" intermediate casing with 150 sacks of cement; drill to total depth with gas or air; set 4½" liner to total depth; perforate and oil-fracture with about 60,000 gallons of oil. Variations are to set slotted liner or complete open-hole. Some natural completions have been made.

RESERVOIR DATA

Productive Area:
- Proved: 1,700 acres
- Unproved: North and south limits of field not defined by dry holes
- Approved Spacing: 80 acres
- No. of Producing Wells: 7
- No. of Abandoned Wells: 18
- No. of Dry Holes: 4

Average Net Pay: Fractured reservoir; gross productive interval ranges from 51 feet to 643 feet and averages 278 feet

Porosity: Fracture porosity

Permeability: Fracture permeability

Water Saturation: Unknown

Initial Field Pressure: Unknown

Type of Drive: Gravity, solution gas

Gas Characteristics and Analysis: Unknown

Oil Characteristics and Analysis: 37° API gravity, 0.1 percent sulfur

Original Gas, Oil, and Water Contact Datums: Variable

Estimated Primary Recovery: Has produced 1,000 barrels per acre to July 1977

Type of Secondary Recovery: None

Estimated Ultimate Recovery: 1,700,000 BO, 1,500,000 MCFG

Present Daily Average Production: 60 BOD, 15 MCFGD, 14 BWD

Market Outlets: Oil, Shell Pipeline Corporation; gas, used for lease operation or vented

FIELD COMMENTARY

The Boulder field is in northwest New Mexico, about sixteen miles northeast of the town of Gavilan on State Highway 96 on the Jicarilla Indian Reservation. It is located on the east flank of the San Juan Basin.

The field is on a monocline imposed on regional west dip. No closure or nose is mapped in the area of the field. Production is from fractures in the Mancos Shale. The cause of the fractures in the San Juan Basin have been discussed by several authors who present different interpretations. The reader is referred to London (1972), and Gorham, and others (1977), for recent reports on fractured Mancos Shale production.

An analysis of a fractured reservoir such as Boulder is a singularly vexatious task because few parameters can be defined adequately. However certain observations can be made:

1. The field has produced 1,700,000 BO, 1,400,000 MCFG, and 700 BW since discovery. Production has ranged from a high of 465,798 BO in 1963 to a low of 16,197 BO in 1975. In July 1977, the field produced 60 BOD. The conclusion is that the field is nearly depleted using present production methods.
2. Water recovery has been reported on completion of some wells: S.O.T. No. 6, SE¼SW¼, sec. 26, T. 28 N., R. 1 W.; S.O.T. No. 7, NW¼NE¼, sec. 35, T. 28 N., R. 1 W.; Gulf No. 1-298, SE¼SE¼, sec. 10, T. 28 N., R. 1 W.; Mobil No. 14-23, SW¼SW¼, sec. 12, T. 28 N., R. 1 W.; and during the completion attempt S.O.T.

No. 8 Jicarilla. SW¼NE¼, sec. 15, T. 28 N., R. 1 W. During July 1977 four wells produced water with oil. Origin of this water is unknown and may come from several zones as different intervals are open for production in various wells (see cross-section). The connection of productive intervals by fracture systems and possible faults seems probable in this field.
3. The field has no limiting dry holes on the north or south, and has had no wells drilled deeper than the Mancos.

Net pay, porosity, permeability, water saturation and drainage area are not known. The reader again is referred to London (1972), Gorham (1977), and others for study results of the East and West Puerto Chiquito fields for which more data is available. These fields are 15 to 20 miles south of Boulder, and some of the data might be applied to the Boulder field.

REFERENCES

Gorham, F. D. Jr., Woodward, L. A., Callender, J. F., and Greer, A. R., 1977, Fracture Permeability in Cretaceous Rocks of the San Juan Basin, *in* San Juan Basin III: New Mexico Geol. Soc. Guidebook, 28th Field Conf., p. 235-241.

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Ira Rineharts Yearbook, 1962.

London, W. W., 1972, Dolomite in Flexure-Fractured Petroleum Reservoirs in New Mexico and Colorado: Am. Assoc. Petroleum Geologists Bull., v. 56, no. 4, p. 815-821.

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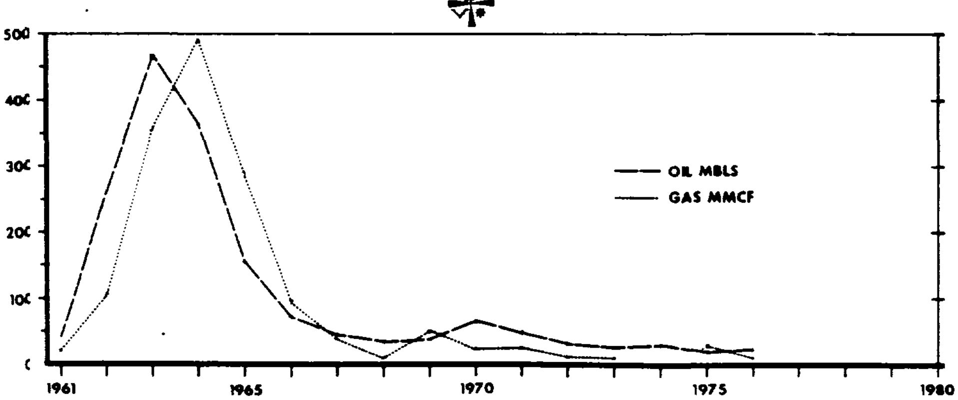
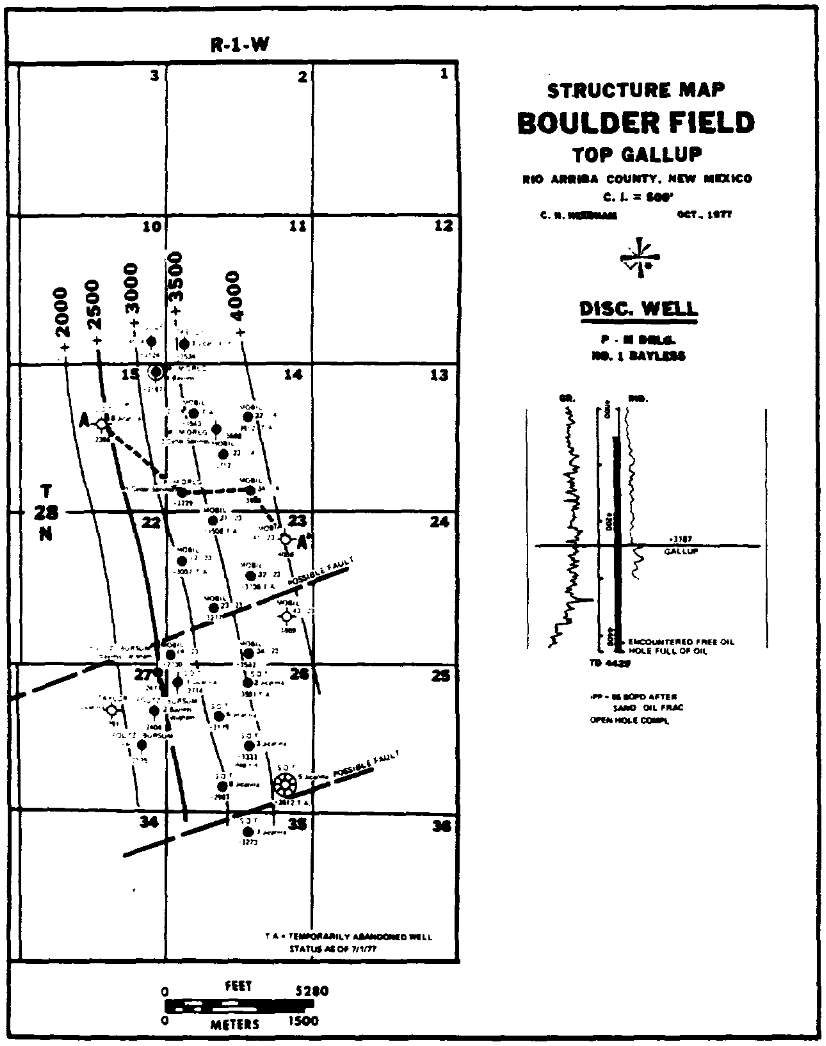
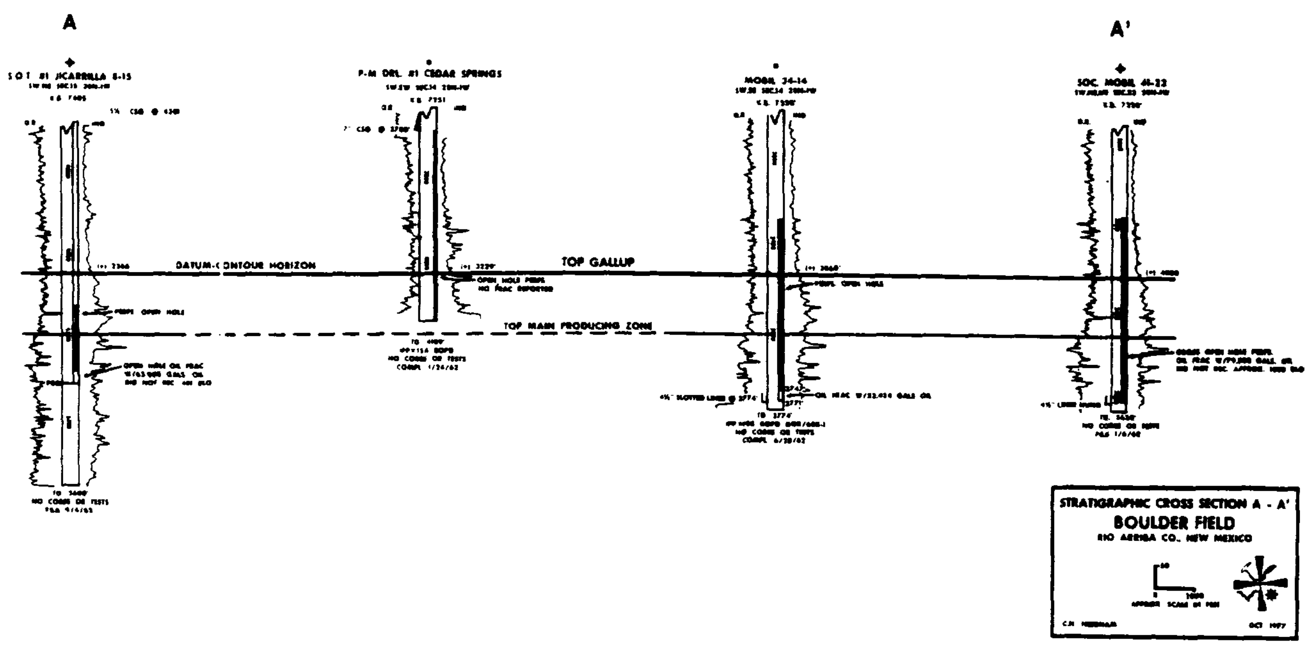
NO. OF WELLS @ YR. END				PRODUCTION: OIL IN BARRELS GAS IN MCF	
YEAR	TYPE	PROD.	S.I./ABND	ANNUAL	CUMULATIVE
1961	OIL	6		40,716	40,716
	GAS			15,608	15,608
1962	OIL	13	10	263,431	304,147
	GAS			104,296	119,904
1963	OIL	21	3	465,798	769,945
	GAS		1	312,545	432,449
1964	OIL	20	3	363,410	1,133,355
	GAS		1	488,425	920,874
1965	OIL	10	10	154,195	1,287,550
	GAS		1	280,493	1,201,367
1966	OIL	12	7	70,629	1,358,179
	GAS		1	98,281	1,299,648
1967	OIL	8	11	44,892	1,403,071
	GAS		1	40,000	1,339,648
1968	OIL	8	11	33,115	1,436,186
	GAS		1	6,968	1,346,616
1969	OIL	9	10	35,492	1,471,678
	GAS		1	48,311	1,394,927
1970	OIL	9	8	64,610	1,536,288
	GAS		1	20,774	1,415,701
1971	OIL	9	8	46,444	1,582,732
	GAS		1	22,880	1,438,581
1972	OIL	9	8	29,361	1,612,093
	GAS		1	9,123	1,447,704
1973	OIL	6	11	23,475	1,635,568
	GAS		1	7,776	1,455,480
1974	OIL	8	9	25,886	1,661,454
	GAS		1	NONE REPORTED	1,455,480
1975	OIL	8	9	16,197	1,677,651
	GAS		1	2,684	1,458,164
1976	OIL	8	9	20,886	1,698,537
	GAS		1	6,868	1,465,032
1977	OIL	7	10	11,022	1,709,559
	GAS		1	6,754	1,471,786 TO 7-1




STRUCTURE MAP
BOULDER FIELD
TOP GALLUP
RIO ARRIBA COUNTY, NEW MEXICO
DISC. WELL
R-1-W
T 28 N
2000
2500
3000
3500
4000
POSSIBLE FAULT
A
A'
GALLUP
FEET 0 5280
METERS 0 1500


A
A'
DATUM-CONTOUR HORIZON
TOP GALLUP
TOP MAIN PRODUCING ZONE
STRATIGRAPHIC CROSS SECTION A - A'
BOULDER FIELD
RIO ARRIBA CO., NEW MEXICO

REFERENCES

1. Frick, Thomas C. and Taylor, William R., Petroleum Production Handbook, Page 37-23.

2. Craft and Hawkins, Applied Petroleum Reservoir Engineering , Page 368.

3. Muskat, Morris, Physical Principles of Oil Production, 1949, Page 487.

4. Lewis, J.O., Gravity Drainage in Oil Fields, Trans AIME, Volume 155, Page 133.

BENSON-MONTIN-GREER DRILLING CORP.
EXHIBIT IN CASE NO. 9111
BEFORE THE OIL CONSERVATION COMMISSION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

MARCH 17, 1988

NOTES ON ANALYSIS OF PRESSURE PULSES GENERATED BY FRAC TREATMENTS IN THE FRACTURED SHALE RESERVOIR OF THE NIOBRARA MEMBER OF THE MANCOS FORMATION IN THE WEST PUERTO CHIQUITO POOL RIO ARRIBA COUNTY, NEW MEXICO

9111 3
BMG
3-17-88

Albert R. Greer

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BENSON-MONTIN-GREER DRILLING CORP.
EXHIBIT IN CASE NO. 9111
BEFORE THE OIL CONSERVATION COMMISSION OF THE
NEW MEXICO DEPARTMENT OF ENERGY AND MINERALS

MARCH 17, 1988

INDEX

SECTION A. NOTES ON ANALYSIS OF PRESSURE PULSES GENERATED BY FRAC TREATMENTS IN THE FRACTURED SHALE RESERVOIR OF THE NIOBRARA MEMBER OF THE MANCOS FORMATION IN THE WEST PUERTO CHIQUITO MANCOS POOL

1. Summary and Discussion (5 pages, white)
2. Plat showing area of frac pulse tests (white)
3. Summary of Four Frac Pulse Tests - West Puerto Chiquito (white)

SECTION B. RESPONSE TO TYPICAL FRAC TREATMENT - WEST PUERTO CHIQUITO MANCOS POOL

1. Introductory page (blue)
2. Graph: Response to Typical Frac (blue)
3. Discussion (yellow)
4. Graph: Response to Typical Frac (yellow)
5. Discussion (blue)
6. Statistics (blue)
7. Discussion (yellow)
8. Statistics (yellow)

SECTION C. RESPONSE TO FRAC TREATMENT: CANADA OJITOS UNIT N-31

1. Introductory page (white)
2. Plat showing area of interference testing (white)
3. Graph: Frac Response in COU E-6 of N-31 Frac (gold)
4. Plat Showing Locations of Wells in the Vicinity of the COU N-31 and COU E-6 (gold)
5. Statistics (pink)
6. Graph: Response to N-31 Frac 4/1/86 (pink)

SECTION D. RESPONSE TO FRAC TREATMENT: DUGAN TAPACITOS 4

1. Introductory page (white)
2. Plat showing area of interference testing (white)
3. Graph: Frac Response in COU E-6 of Tapacitos 4 Frac (yellow)
4. Plat Showing Locations of Wells in the Vicinity of the Dugan Tapacitos 4 and COU E-6 (yellow)
5. Statistics (tan)
6. Graph: Response to Tapacitos 4 Frac (tan)

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A

NOTES ON ANALYSIS OF PRESSURE PULSES GENERATED BY FRAC TREATMENTS IN THE FRACTURED SHALE RESERVOIR OF THE NIOBRARA MEMBER OF THE MANCOS FORMATION IN THE WEST PUERTO CHIQUITO POOL RIO ARRIBA COUNTY, NEW MEXICO

MARCH, 1988

SUMMARY

Analyses of pressure responses to four frac treatments showed an average pore volume of øh of approximately .34 (equivalent to a volume of stock tank oil in place of about 2000 barrels per acre) for three of the tests in which three zones were open. In the test with only two zones open in the treated well, a value of 1100 stock tank barrels per acre was determined. These values are consistent with those derived from interference tests twenty years ago and from approximate material balance estimates.

An average value for Kh/u was about 80 darcy feet. Translated to Koh: three wells were in the range of 10 to 20 darcy feet; and one was 50 darcy feet. These values, too, are consistent with that estimated 20 years ago for the high capacity fracture system and are believed to be more representative of it than that for the total reservoir combination of high capacity fracture system and tight blocks. Some influence from the tight blocks is believed to show in the tests that covered up to four days. In all instances curve matching at later times shows lower values of Kh/u; which is believed may be the consequence of greater diffusion from the high capacity system into the tight blocks as time increases.

Of significance is the fact that the pore volumes associated with these high transmissibilities undoubtedly represent a large percent of the total pore volume. High values of Koh associated with large part of the total oil in place means that gravity drainage is a viable recovery mechanism for which to strive.

Three of the tests described herein were conducted pursuant to suggestion by members of the Gavilan Engineering Committee. Results of the first two tests provided to the Engineering Committee revealed that an empirical relation appeared to exist of the frac volume, frac rate and distances between wells; suggesting that the data might be subject to analysis. However, before the Engineering Committee undertook an analysis of the subject, the Committee's work was suspended.

The enclosed analysis is hereby provided, in lieu of the otherwise joint effort of the Committee members.

DISCUSSION

In a reservoir such as the one being produced in the West Puerto Chiquito pool in which a high capacity fracture system extends over the reservoir, it is to be expected that a fracture treatment of the size typically used would create a pressure pulse in nearby (up to 2 miles) wells measureable with the sensitive pressure equipment that has become generally available in the 1980's. Further it is to be expected (intuitively) that the characteristics of the reservoir governing the behavior of the pressure pulse would be more that of the high capacity fracture system rather than that of the tight blocks; although as the length of time from the frac treatment increases, diffusion from the high capacity system into some of the tight blocks should occur. It is of interest to examine interference testing of some of the fracture treatments in an effort to add additional knowledge about the reservoir's physical properties.

A virtue of frac pulse testing as opposed to normal interference testing - particularly for areas of low capacity wells - the frac pulse test can yield results in a relatively short length of time, requiring much shorter shut-in periods of wells in the vicinity, minimizing the revenue loss attendant with long shut-in periods.

The explicit analytical solution of the reservoir pressure response to a frac treatment with a long fracture in a finite reservoir appears, at best, difficult to use; particularly for analysis of the subject reservoir in which none of the physical properties, permeability, porosity or pay thickness, are individually known. However, given the large areal extent of the reservoir, the point source (exponential integral) solution should yield results accurate enough for practical interpretation of some combinations of the reservoir parameters (Kh/u and ∅h, John Lee reference 1).

Qualitatively, it is to be expected that the first part of a pressure pulse generated by a frac treatment will arrive earlier and in greater magnitude - than that for a similar volume injected without fracturing the formation.

Once the frac treatment has ended, however, the continuing diffusion can be expected to follow that described by the diffusivity equations; and if the fracture blocks are small compared to the overall "area of influence" of the test, the flow system will approach that of radial - and the EI solution of the diffusivity equation will yield reasonably accurate results.

Since the diffusion of the pressure pulse will follow first through the high capacity fracture system and then into the fracture blocks, it is to be further expected that analyses of the earlier part of the test will reflect more of the character of the high capacity fracture system than that of the overall average.

The two factors limiting the accuracy of the EI solution are that the reservoir is of finite size and that the induced fracture causes the pressure effects of the injected fluid to deviate from that which would obtain for a "point source".

As to the first matter, the pressure response will deviate from that for the infinite solution only when the situation is such that boundary conditions become significant; and given the dimensions of the reservoir and the distance between the treated well and the observation wells for the tests run in West Puerto Chiquito, this influence of boundary conditions probably will not be significant until times longer than those occurring in the subject tests.

Also as to the deviation brought about by the effective wellbore radius being greater than a point source, estimates of the amount of this deviation (Mueller and Witherspoon reference 2) suggest that for the conditions of these tests and for assumed effective rw's of less than 250' that the amount of this error may not be significant for the points of curve matching used herein. (Times at which the error from this source is 10% and 2% are shown on the schedules and graphs herein for each test).

From a practical analysis standpoint and the fact that given the nature of the reservoir and the high capacity fracture system, it will be impossible to determine - as can be done in some reservoirs - the length of the induced fracture. Given this uncertainty - and the small difference in the exact solution with the EI formula for the probable ranges of "effective rw" - use of the more cumbersome exact solution to the diffusivity equation for these frac pulse tests does not appear warranted.

Since pressure responses for observation wells located more than a mile from the treated well may have values of less than 1#, it is necessary to use sensitive pressure measuring equipment, and to eliminate interference effects of other wells. In the instance of some of the tests in the Canada Ojitos Unit, all wells within a township were shut in to minimize the effect of interference from other wells. Here reliable data was obtained. In some of the other tests the pressure pulses were substantially greater than the interference effect of producing wells, and consequently that data is believed to be reasonably accurate.

Although either two or three zones were open during the tests (a situation less desirable than that for a single zone) it is believed that the characteristics of - or averages of - the dominant zone(s) will be reflected in the analyses.

The analysis is simply that of the pulse testing procedure, except that the information is limited to a single pulse. The herein-recommended procedure is to calculate a series of curves, assuming for each curve a value of Kh/u and diffusivity constant. By curve matching against the field data determine directly the appropriate value of Kh/u and, indirectly (Appendix I) calculate øh.

Since free gas that occurs after reservoir pressures drop below the bubble point greatly increases the overall mobility (John Lee, reference 3), and since the A and B zones appear in places to have free gas indigenous, the diffusivity constant is high - both for pressures above the bubble point and below the bubble point.

From the 1965 interference test, it was determined that - on average (combination of both the tight blocks and high capacity fracture system) - the ratio of K/ø was in excess of 10 darcys; and that K/ø, as well as Kh, for the high capacity system alone should be substantially higher. The frac pulse testing shows this to indeed be the case.

From the herein-described frac pulse tests, the curve matching showed diffusivity constants in a small range of 4×10^6 to 6×10^6. It is believed that all of these frac pulse tests were conducted when pressure of the dominant zones was below the bubble point; and although compressibility will vary some for the different tests, for the comparative analyses shown herein, a system compressibility of 350×10^{-6} per pound was used for all tests to compute øh.

Although Kh, Koh and KTh/uT (total mobility) are independent of compressibility, it is necessary to know system compressibility to determine øh. For a pressure of 1400# (intermediate pressure for all of the tests) the main factor affecting compressibility is that of the saturated oil (approximately 300×10^{-6}). Cg is approximately 800×10^{-6} and Cf is estimated at 15×10^{-6}. For zero to 10% gas saturation the above translates to system compressibility ranging from about 315×10^{-6} to 365×10^{-6}; so the value of 350×10^{-6} should be within about 10% in all of the tests. Not knowing exactly the gas saturation, it is doubtful that more precise figures can be developed.

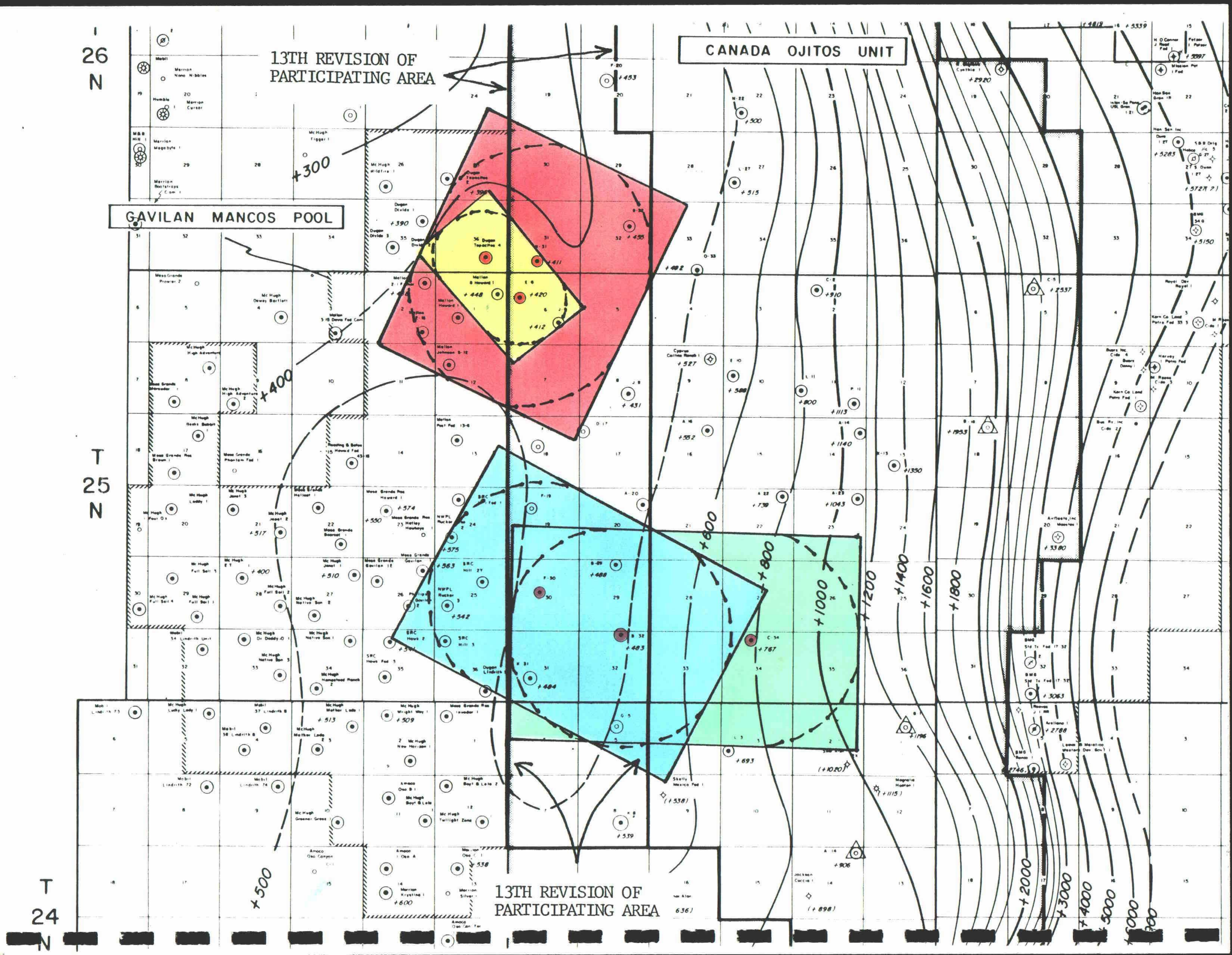
To convert the values of Kh/u to Koh requires information independent of the frac pulse data. Apparently all that is required is the GOR (and the viscosity of the oil and the gas along with oil and gas formation volume factors, Bo and Bg) (Appendix II).

For any given PVT values, the relation of total mobility to Koh as defined by Kg/Ko, Kro, Krg is such that it can be determined independently of the knowledge of each of these parameters. There appears to be a unique relation between KTh/ut and Koh, such that Koh can be determined from a knowledge of only total mobility and GOR (Appendix II).

Summary of test results of areas of investigation are shown on the pages next following. The areas shown on the graphs are the minimum areas of investigation (the ellipsoid shaped areas inside the "influence rectangle") depicted on the plat (John Lee, reference 4).

Individual tests are detailed in the succeeding sections.

(Technical note: because of the relatively high injection rates and the fact that the calculated pressure response is the result of differences in computed values - the consequence of superposition - it is necessary that the EI function be more accurately determined than that for typical pulse testing. The degree of accuracy required can be determined by computing the pressure if injection were continous, as shown on some of the examples herein. Generally, a value of the EI function accurate to 6 or 8 significant figures is suitable. A computer with basic precision of 14 or 16 significant figures will yield that accuracy for EI(-x) for values of x less than 10. If the computations are such that values of x exceed 10, higher precision may be required. In this respect, it is helpful to know - print-out - the values of x as shown in the examples herein.)



T 26 N
T 25 N
T 24 N
13TH REVISION OF PARTICIPATING AREA
GAVILAN MANCOS POOL
CANADA OJITOS UNIT
+300
+400
+500
+600
+800
+1000
+1200
+1400
+1600
+1800
+2000
+3000
+4000
+5000
+6000
13TH REVISION OF PARTICIPATING AREA

SUMMARY OF FOUR FRAC PULSE TESTS
WEST PUERTO CHIQUITO POOL

1) Well Pair	COU N-31 / COU E 6	Tapacitos 4 / COU E 6	COU F-30 / COU D 32	COU C-34 / COU D 32
2) Color of Test Area on Facing Page	red	yellow	blue	green
3) Date of Treatment	4/1/86	2/13/86	9/4/86	4/23/87
Zones Open				
4) Treated Well	A, B, C	A, B, C	A, B, C	A, B
5) Observation Well	A, B, C	A, B, C	A, B, C	A, B, C
Approximate Area of Investigation (Influence)				
6) (Acres)	5100	1200	6000	6500
7) at ending day ( )	(4)	(.7)	(4)	(4)
8) Pore Volume, øh	.25	.47	.31	.19
9) Pore Volume, Stock Bbls/Acre	1500	2800	1800	1100
10) Average Transmissibility, Kh/u Darcy feet/centipoise	64	125	68	48
11) Estimated GOR (cubic feet/bbl) for Area of Influence	2000	800	1050	1200
12) Ratio of Koh to Kh/u for GOR (graph, page 4 of Appendix II)	.19	.41	.33	.30
13) Koh (from lines 11 and 12) (darcy feet)	12	51	22	14

Note: In heavy black outline as noted on plat on facing page are boundaries of the 13th revision of the Canada Ojitos Unit Participating Area (area requested for inclusion in pressure maintenance project).

B

RESPONSE TO TYPICAL FRAC TREATMENT
WEST PUERTO CHIQUITO MANCOS POOL

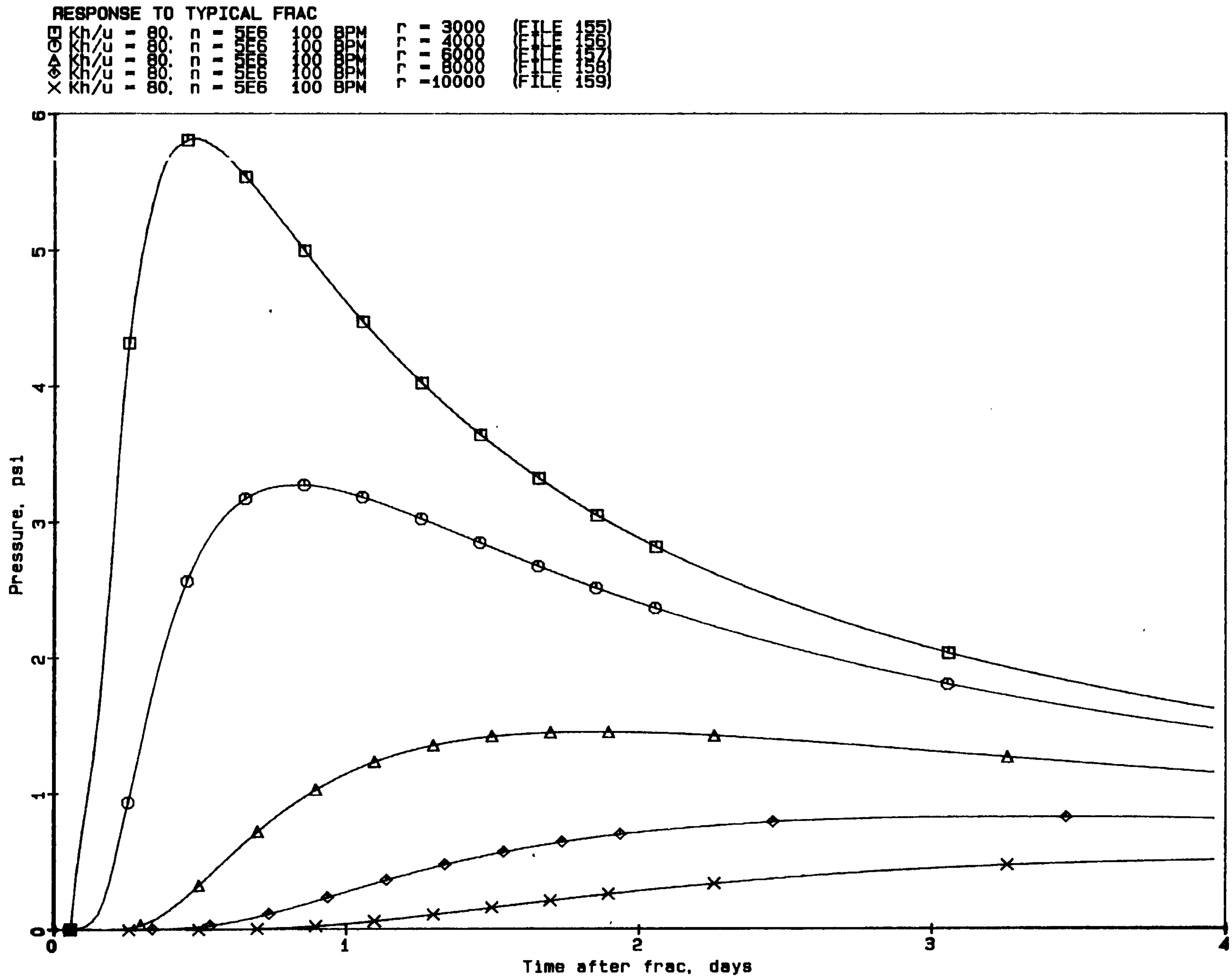
Analyses of four tests in West Puerto Chiquito showed for Kh/u a value of about 80, with a diffusivity constant of about 5 x 10. From this information a family of curves was developed showing the pressure response to be anticipated at varying times for wells at varying distances from the treated well. These curves are set out on the facing page showing pressure responses in wells located from 3,000' to 10,000' from a well with a fracture treatment of 8,000 barrels of slurry pumped at a rate of 100 BPM.

The curves are based on infinite conditions.

Pressure shown on the vertical scale is the pressure change resulting from the frac treatment.

As can be seen from these typical curves, there is enough "character" to the curves and pressure differential that with pressure measuring equipment capable of measuring pressure differences to .01 of a pound that it is possible to obtain information which properly analyzed will reflect properties of the reservoir. Of particular significance is the fact that although the pumping time for the typical frac treatment is only a small portion of a day (1-1/2 hours) the "pressure pulse" spreads out in time as the distance increases from the treated well.

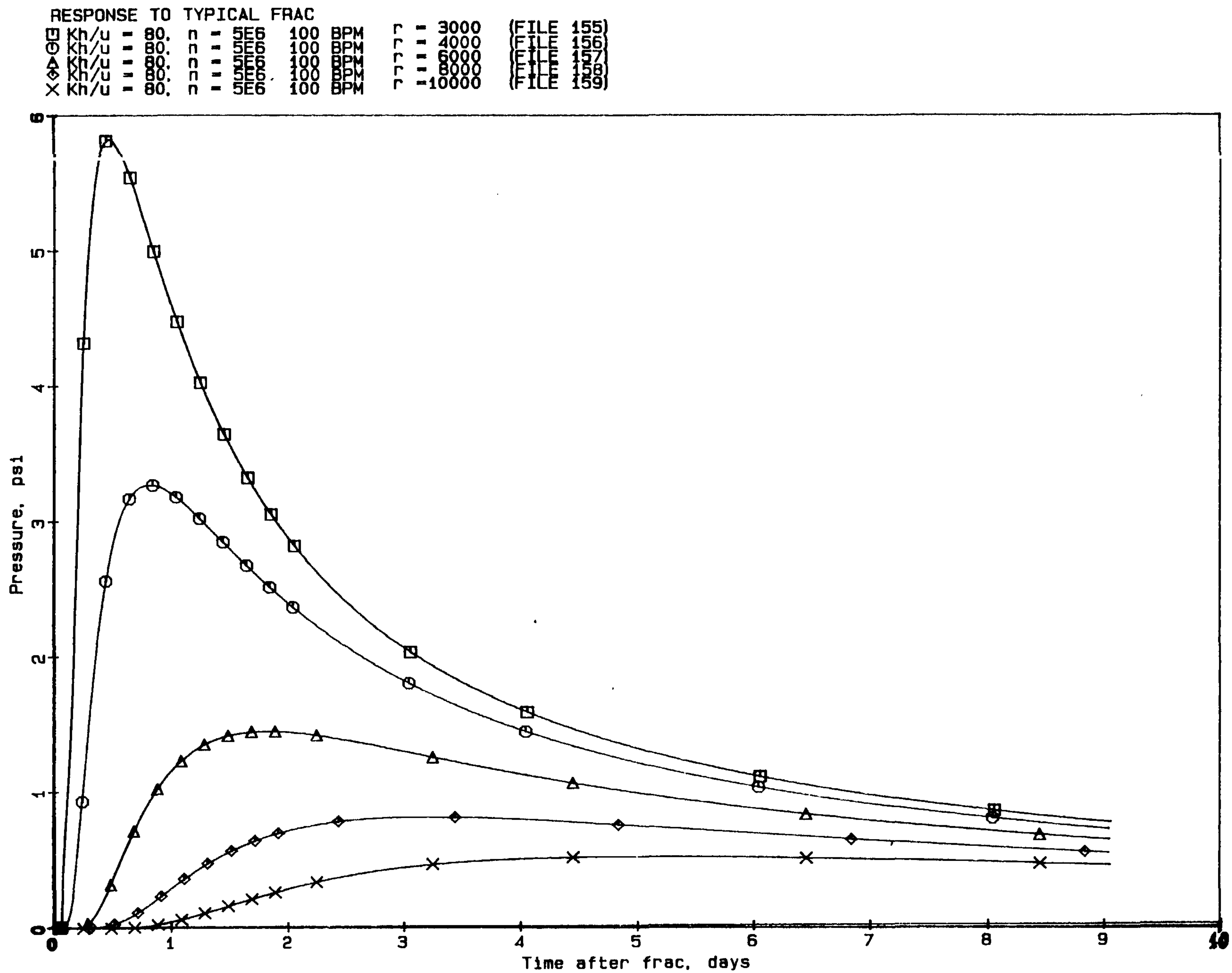
For distances of 8,000 to 10,000 feet, the pressure is still rising after 4 days.


RESPONSE TO TYPICAL FRAC
Kh/u = 80. n = 5E6 100 BPM r = 3000 (FILE 155)
Kh/u = 80. n = 5E6 100 BPM r = 4000 (FILE 156)
Kh/u = 80. n = 5E6 100 BPM r = 6000 (FILE 157)
Kh/u = 80. n = 5E6 100 BPM r = 8000 (FILE 158)
Kh/u = 80. n = 5E6 100 BPM r =10000 (FILE 159)
Pressure, psi
Time after frac, days
0
1
2
3
4
5
6

RESPONSE TO TYPICAL FRAC TREATMENT
WEST PUERTO CHIQUITO MANCOS POOL

On the facing page are the same curves as those preceding with the time scale expanded out to 9 days.

Here it can be seen that the pressure difference at 9 days is drawing together for observation wells at varying distances from the treated well.


RESPONSE TO TYPICAL FRAC
Kh/u = 80. n = 5E6 100 BPM r = 3000 (FILE 155)
Kh/u = 80. n = 5E6 100 BPM r = 4000 (FILE 156)
Kh/u = 80. n = 5E6 100 BPM r = 6000 (FILE 157)
Kh/u = 80. n = 5E6 100 BPM r = 8000 (FILE 158)
Kh/u = 80. n = 5E6 100 BPM r =10000 (FILE 159)
Pressure, psi
Time after frac, days
0
1
2
3
4
5
6
7
8
9
10

RESPONSE TO TYPICAL FRAC TREATMENT
WEST PUERTO CHIQUITO MANCOS POOL

On the opposite page is a print-out of some of the statistics of interest in the computations.

The exponential integral solution is not exact at time periods in which nt/rw^2 is less than 100.

For a well with an induced fracture, the effective rw will approximate 1/4 of the fracture length from tip to tip; which for a 1000' fracture would be an effective rw of 250'. This value (nt/rw^2) is determined for rw's of 1, 10, 100 and 250 feet for each calculated point.

If this value is less than 100, then the amount of difference of the EI solution from the exact solution can be approximated from the value of nt/r^2 as shown in the last column of the statistics and comparing it with the graph on page 473 of reference 2, or expanded graph, reference 2 (yellow color).

For the tests herein for effective rw's of 250' (induced fracture lengths of 1000') the time at which the error reduces to 10%, and again at 2%, is shown by highlighting on both the schedules and the graphs. At times earlier than those shown by this highlighting, the curves would be expected not to match.

THE COMPUTATION OF PRESSURE RESPONSE TO FRAC TREATMENT
(EI SOLUTION BY SUPERPOSITION)

THE VALUE OF Pump Rate Bbls of Fluid/Minute = 100
THE VALUE OF q (Bbls of Fluid/Day) = 144000 BFPD

The Value of Kh/u (Darcy ft/cp) is 80

The Value of B (FVF) is 1
The Value of r (ft) is 3000
The Value of n (dc) is 5000000
The Injection Time (Days) is .056
The Increment of dt (1) is .1
The Ending day of dt (1) is 2
The Increment of dt (2) is .5
The Ending day of dt (2) is 4
The Increment of dt (3) is 1
The Ending day of dt (3) is 10
The Day Shut In is .056
The Beginning Pressure is 0
The Output File name is is FILE155

dc=diffusivity constant
=6.328K/((a)(c)(u))
a=porosity,fraction
c=compressibility
u=viscosity,cp

IF X > 20 THEN EI(-X) = 0

If $(n)(t)/(rw)^2$ greater than or equal to 999 then it prints 999

TIME SINCE FRAC START (DAYS)	PRESSURE RESPONSE TO FRAC AT r (PSI)	PRESSURE AT r IF CONTINUOUS PUMPING (PSI)	VALUE OF X IN EI FUNCTION	$(n)(t)/(rw)^2$ rw = 1	rw = 10	rw = 100	rw = 250	$(n)(t)/(r^2)$
0.06	0.00	0.005	8.036	999	999	28	4	0.0311
0.16	1.66	1.922	2.885	999	999	78	12	0.0867
0.26	4.32	8.735	1.758	999	999	128	20	0.1422
0.36	5.49	18.208	1.264	999	999	178	28	0.1978
0.46	5.81	28.511	0.987	999	999	228	36	0.2533
0.56	5.75	38.822	0.809	999	999	278	44	0.3089
0.66	5.54	48.800	0.686	999	999	328	52	0.3644
0.76	5.27	58.317	0.595	999	999	378	60	0.4200
0.86	4.99	67.342	0.526	999	999	428	68	0.4756
0.96	4.72	75.881	0.471	999	999	478	76	0.5311
1.06	4.47	83.961	0.428	999	999	528	84	0.5867
1.16	4.24	91.614	0.389	999	999	578	92	0.6422
1.26	4.02	98.874	0.358	999	999	628	100	0.6978
1.36	3.82	105.771	0.332	999	999	678	108	0.7533
1.46	3.64	112.337	0.309	999	999	728	116	0.8089
1.56	3.47	118.599	0.289	999	999	778	124	0.8644
1.66	3.32	124.581	0.272	999	999	828	132	0.9200
1.76	3.18	130.305	0.256	999	999	878	140	0.9756
1.86	3.04	135.792	0.242	999	999	928	148	1.0311
1.96	2.92	141.060	0.230	999	999	978	156	1.0867
2.06	2.81	146.124	0.219	999	999	999	164	1.1422
2.56	2.36	168.856	0.176	999	999	999	204	1.4200
3.06	2.03	188.187	0.147	999	999	999	244	1.6978
3.56	1.78	204.989	0.127	999	999	999	284	1.9756
4.06	1.58	219.843	0.111	999	999	999	324	2.2533
5.06	1.29	245.203	0.089	999	999	999	404	2.8089
6.06	1.10	266.350	0.074	999	999	999	484	3.3644
7.06	0.95	284.484	0.064	999	999	999	564	3.9200
8.06	0.84	300.356	0.056	999	999	999	644	4.4756
9.06	0.75	314.466	0.050	999	999	999	724	5.0311

RESPONSE TO TYPICAL FRAC TREATMENT
WEST PUERTO CHIQUITO MANCOS POOL

Here attention is called to the computation for an observation well located 10,000' from the treated well and the fact that the pressure response (second column) increases up to a period of six days and then commences a very slow decrease.

THE COMPUTATION OF PRESSURE RESPONSE TO FRAC TREATMENT
(EI SOLUTION BY SUPERPOSITION)

THE VALUE OF Pump Rate Bbls of Fluid/Minute = 100
THE VALUE OF q (Bbls of Fluid/Day) = 144000 BFPD

The Value of Kh/u (Darcy ft/cp) is 80

The Value of B (FVF) is 1
The Value of r (ft) is 10000
The Value of n (dc) is 5000000
The Injection Time (Days) is .056
The Increment of dt (1) is .1
The Ending day of dt (1) is 2
The Increment of dt (2) is .5
The Ending day of dt (2) is 4
The Increment of dt (3) is 1
The Ending day of dt (3) is 10
The Day Shut In is .056
The Beginning Pressure is 0
The Output File name is is FILE159

dc=diffusivity constant
=6.328K/((a)(c)(u))
a=porosity,fraction
c=compressibility
u=viscosity,cp

IF X > 20 THEN EI(-X) = 0

If $(n)(t)/(rw)^2$ greater than or equal to 999 then it prints 999

TIME SINCE FRAC START (DAYS)	PRESSURE RESPONSE TO FRAC AT r (PSI)	PRESSURE AT r IF CONTINUOUS PUMPING (PSI)	VALUE OF X IN EI FUNCTION	$(n)(t)/(rw)^2$ rw = 1	rw = 10	rw = 100	rw = 250	$(n)(t)/(r^2)$
0.06	0.00	0.000	89.286	999	999	28	4	0.0028
0.16	0.00	0.000	32.051	999	999	78	12	0.0078
0.26	0.00	0.000	19.531	999	999	128	20	0.0128
0.36	0.00	0.000	14.045	999	999	178	28	0.0178
0.46	0.00	0.000	10.965	999	999	228	36	0.0228
0.56	0.00	0.002	8.993	999	999	278	44	0.0278
0.66	0.00	0.007	7.622	999	999	328	52	0.0328
0.76	0.01	0.023	6.614	999	999	378	60	0.0378
0.86	0.02	0.055	5.841	999	999	428	68	0.0428
0.96	0.04	0.112	5.230	999	999	478	76	0.0478
1.06	0.05	0.199	4.735	999	999	528	84	0.0528
1.16	0.08	0.325	4.325	999	999	578	92	0.0578
1.26	0.10	0.492	3.981	999	999	628	100	0.0628
1.36	0.12	0.703	3.687	999	999	678	108	0.0678
1.46	0.15	0.962	3.434	999	999	728	116	0.0728
1.56	0.18	1.267	3.213	999	999	778	124	0.0778
1.66	0.20	1.618	3.019	999	999	828	132	0.0828
1.76	0.23	2.016	2.847	999	999	878	140	0.0878
1.86	0.25	2.458	2.694	999	999	928	148	0.0928
1.96	0.28	2.941	2.556	999	999	978	156	0.0978
2.06	0.30	3.465	2.432	999	999	999	164	0.1028
2.56	0.39	6.606	1.956	999	999	999	204	0.1278
3.06	0.45	10.409	1.636	999	999	999	244	0.1528
3.56	0.49	14.638	1.406	999	999	999	284	0.1778
4.06	0.51	19.123	1.233	999	999	999	324	0.2028
5.06	0.52	28.412	0.989	999	999	999	404	0.2528
6.06	0.52	37.704	0.826	999	999	999	484	0.3028
7.06	0.50	46.744	0.709	999	999	999	564	0.3528
8.06	0.48	55.423	0.621	999	999	999	644	0.4028
9.06	0.45	63.705	0.552	999	999	999	724	0.4528

C

RESPONSE TO FRAC TREATMENT

Treated well: Canada Ojitos Unit N-31 (Sec. 31, T-26N, R-1W)

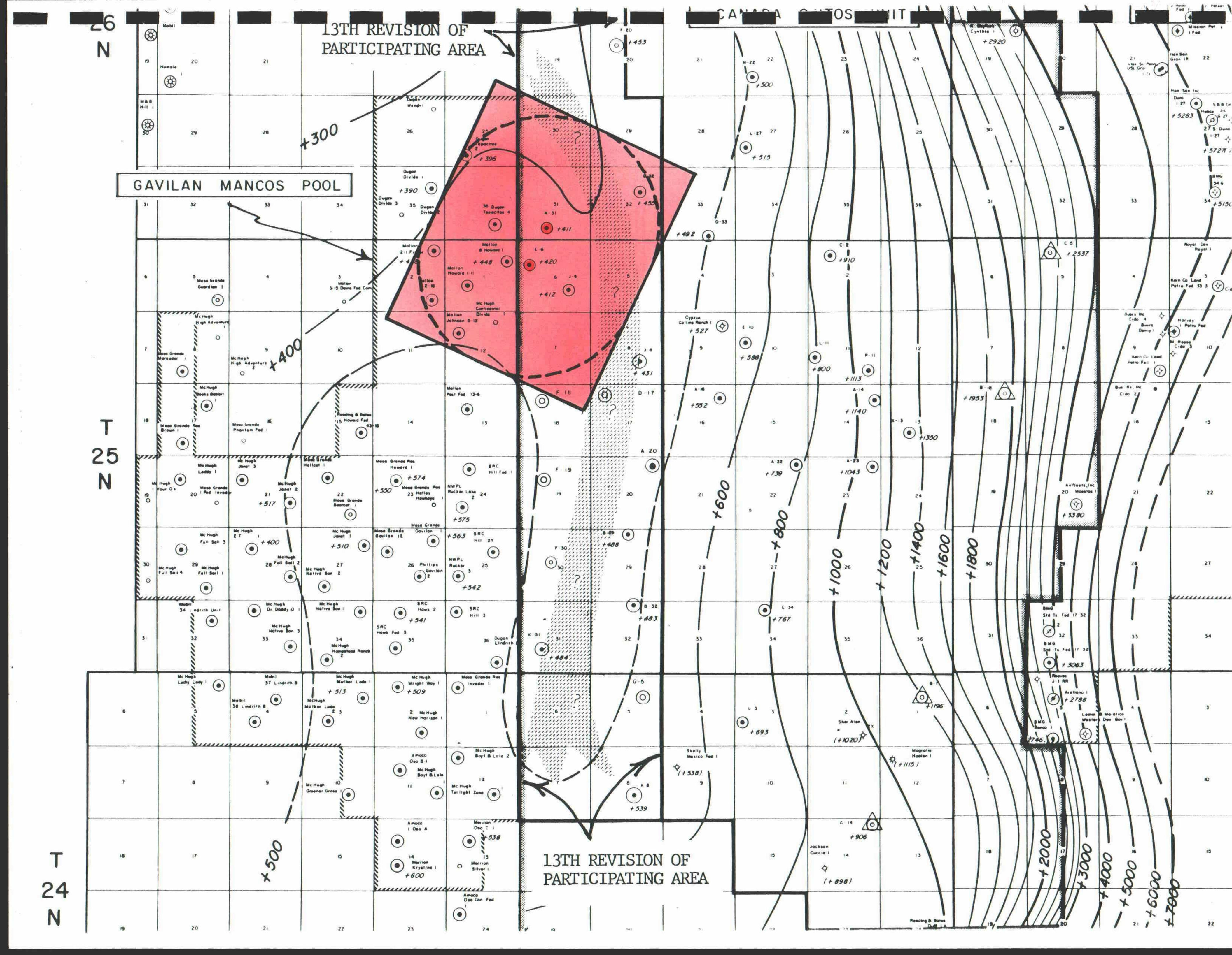
Observation well: Canada Ojitos Unit E-6 (Sec. 6, T-25N, R-1W)

Date: April 1, 1986

See plat on facing page.

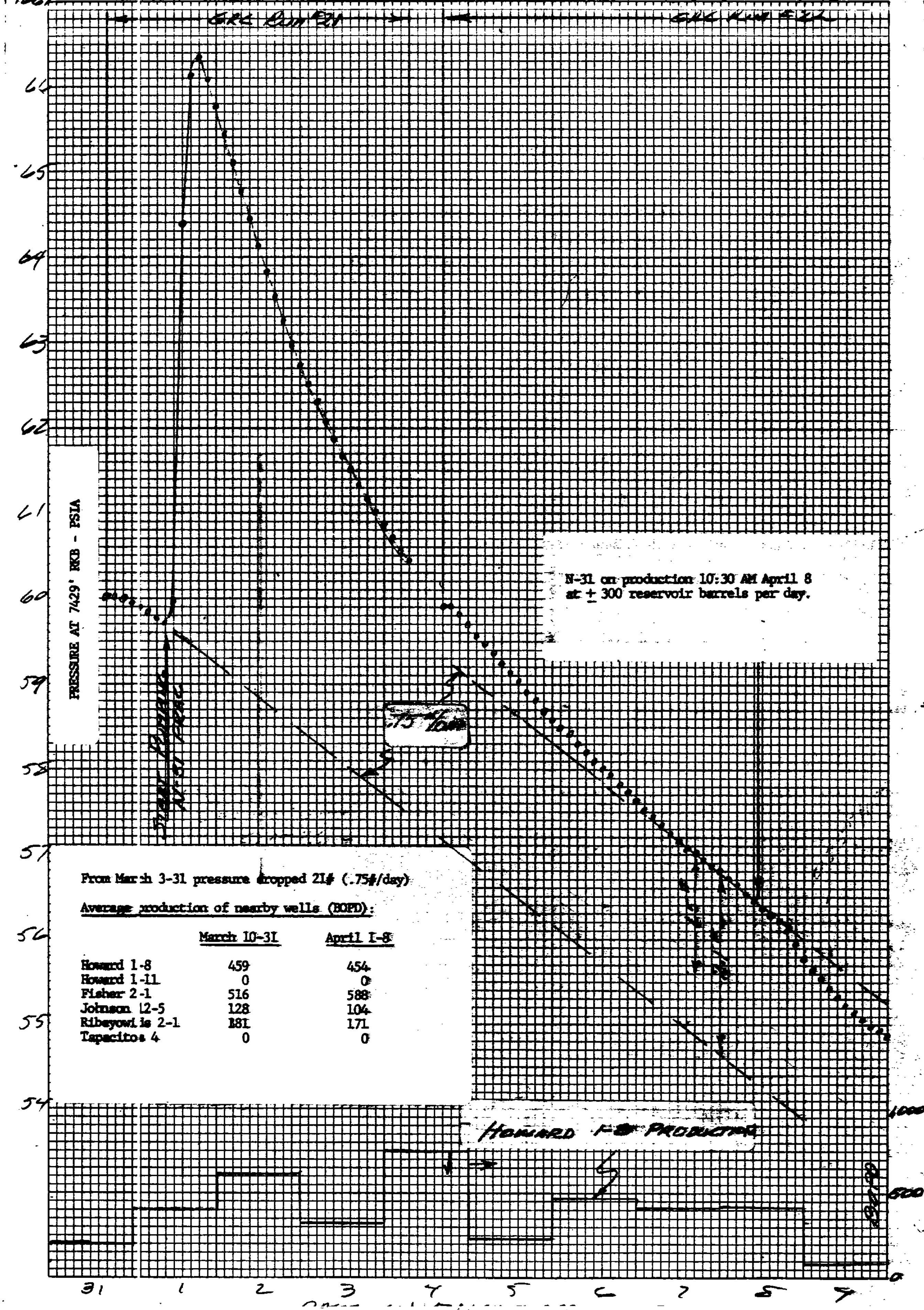
Test Summary of Area and Pore Space:

Area of Investigation at 4 days: approximately 5,000 acres
Pore space, ϕh = .25 or 1500 stock tank barrels per acre.
A, B and C zones open.



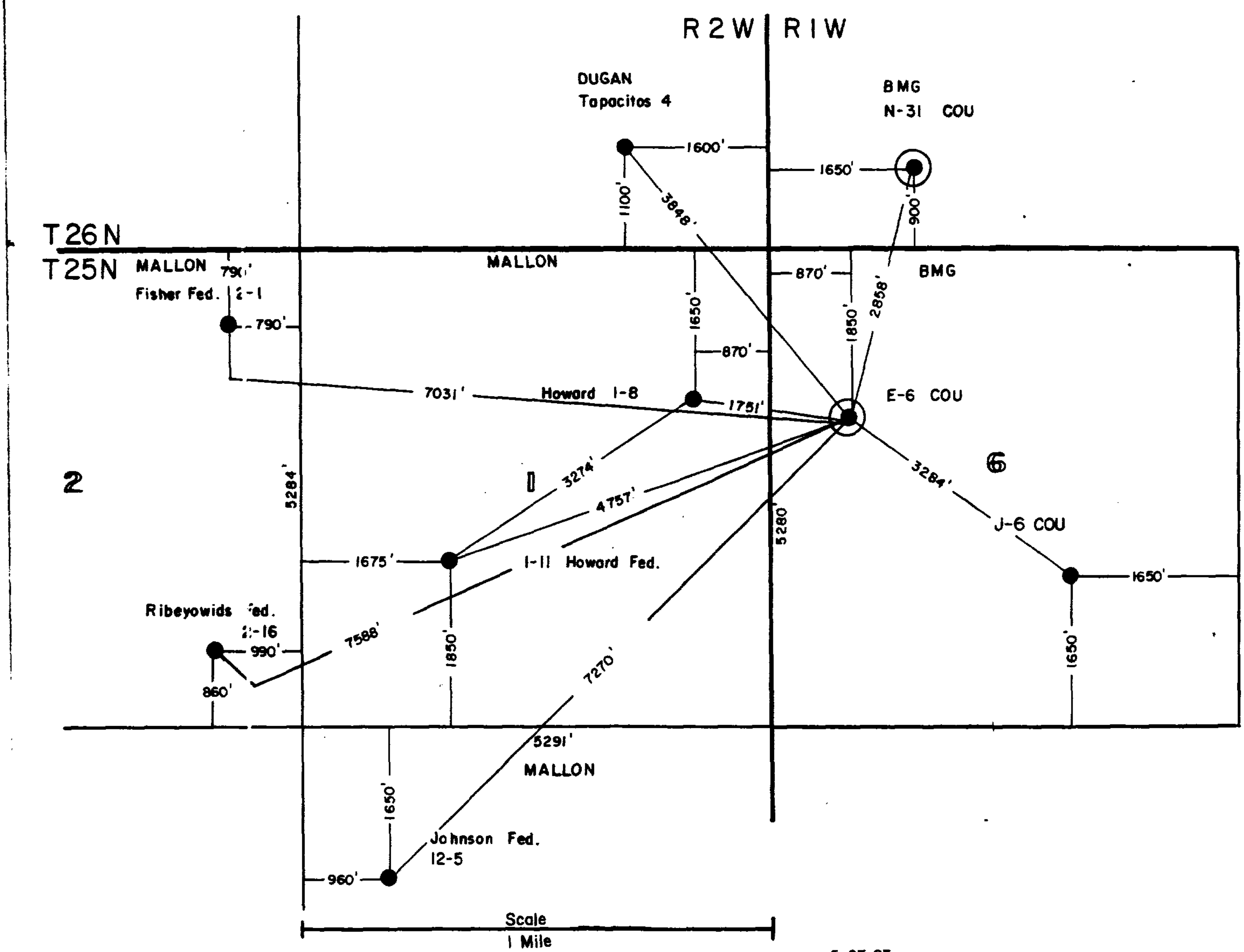
13TH REVISION OF PARTICIPATING AREA
GAVILAN MANCOS POOL
CANADA OJITOS UNIT
T 25 N
T 24 N
26 N
+300
+400
+500
+600
+800
+1000
+1200
+1400
+1600
+1800
+2000
+3000
+4000
+5000
+6000
+7000

FRAC RESPONSE IN CDU E-6 of N-31 FRAC



	March 10-31	April 1-8
Howard 1-8	459	454
Howard 1-11	0	0
Fisher 2-1	516	588
Johnson 12-5	128	104
Ribeyowids 2-1	181	171
Tapacitos 4	0	0

PLAT SHOWING LOCATIONS OF WELLS
IN THE VICINITY OF THE
CANADA OJITOS UNIT N-31
AND
CANADA OJITOS UNIT E-6
FRAC TREATMENT INTERFERENCE TEST



10/86

5-27-87
Revised: 6-23-86

THE COMPUTATION OF PRESSURE RESPONSE TO FRAC TREATMENT
(EI SOLUTION BY SUPERPOSITION)

THE VALUE OF Pump Rate Bbls of Fluid/Minute = 111
THE VALUE OF q (Bbls of Fluid/Day) = 159840 BFPD

The Value of Kh/u (Darcy ft/cp) is 55

dc=diffusivity constant
=6.328K/((a)(c)(u))
a=porosity,fraction
c=compressibility
u=viscosity,cp

The Value of B (FVF) is 1
The Value of r (ft) is 2858
The Value of n (dc) is 4000000
The Injection Time (Days) is .0468
The Increment of dt (1) is .1
The Ending day of dt (1) is 2
The Increment of dt (2) is .5
The Ending day of dt (2) is 4
The Increment of dt (3) is 1
The Ending day of dt (3) is 10
The Day Shut In is .0468
The Beginning Pressure is 0
The Output File name is is FILE146

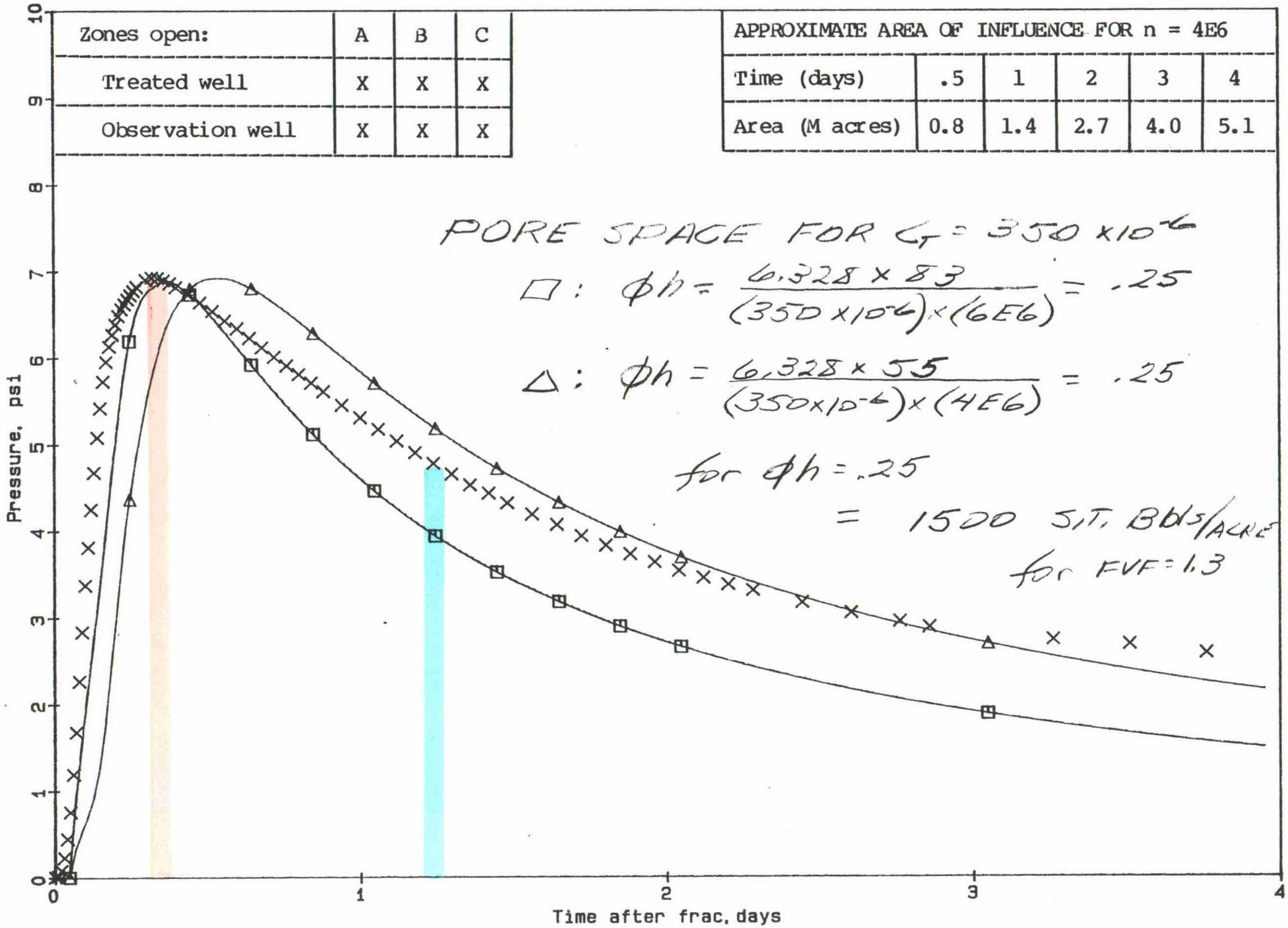
IF X > 20 THEN EI(-X) = 0

If (n)(t)/(rw)² greater than or equal to 999 then it prints 999

TIME SINCE FRAC START (DAYS)	PRESSURE RESPONSE TO FRAC AT r (PSI)	PRESSURE AT r IF CONTINUOUS PUMPING (PSI)	VALUE OF X IN EI FUNCTION	(n)(t)/(rw)² rw = 1	rw = 10	rw = 100	rw = 250	(n)(t)/(r²)
0.05	0.00	0.000	10.908	999	999	19	3	0.0229
0.15	1.26	1.471	3.478	999	999	59	9	0.0719
0.25	4.36	9.132	2.069	999	999	99	16	0.1209
0.35	6.12	21.401	1.472	999	999	139	22	0.1698
0.45	6.79	35.631	1.143	999	999	179	29	0.2188
0.55	6.92	50.389	0.934	999	999	219	35	0.2678
0.65	6.79	64.997	0.789	999	999	259	41	0.3167
0.75	6.56	79.149	0.684	999	999	299	48	0.3657
0.85	6.28	92.720	0.603	999	999	339	54	0.4147
0.95	5.98	105.672	0.539	999	999	379	61	0.4637
1.05	5.70	118.011	0.488	999	999	419	67	0.5126
1.15	5.43	129.761	0.445	999	999	459	73	0.5616
1.25	5.17	140.956	0.409	999	999	499	80	0.6106
1.35	4.94	151.634	0.379	999	999	539	86	0.6595
1.45	4.71	161.831	0.353	999	999	579	93	0.7085
1.55	4.51	171.581	0.330	999	999	619	99	0.7575
1.65	4.32	180.919	0.310	999	999	659	105	0.8064
1.75	4.14	189.873	0.292	999	999	699	112	0.8554
1.85	3.98	198.471	0.276	999	999	739	118	0.9044
1.95	3.83	206.739	0.262	999	999	779	125	0.9534
2.05	3.69	214.700	0.249	999	999	819	131	1.0023
2.55	3.11	250.556	0.200	999	999	999	163	1.2472
3.05	2.68	281.180	0.168	999	999	999	195	1.4920
3.55	2.36	307.877	0.144	999	999	999	227	1.7369
4.05	2.10	331.530	0.126	999	999	999	259	1.9817
5.05	1.73	372.003	0.101	999	999	999	323	2.4714
6.05	1.47	405.826	0.084	999	999	999	387	2.9612
7.05	1.27	434.872	0.072	999	999	999	451	3.4509
8.05	1.12	460.321	0.063	999	999	999	515	3.9406
9.05	1.01	482.965	0.056	999	999	999	579	4.4303

RESPONSE TO N-31 FRAC 4/1/86

× COU E-6 (FILE COUN31)
△ Kh/u = 55, n = 4E6 (FILE 146)
⊡ Kh/u = 83, n = 6E6 (FILE 189)



D

RESPONSE TO FRAC TREATMENT

Treated well: Dugan Tapacitos 4 (Sec. 31, T-26N, R-2W)

Observation well: Canada Ojitos Unit E-6 (Sec. 6, T-25N, R-1W)

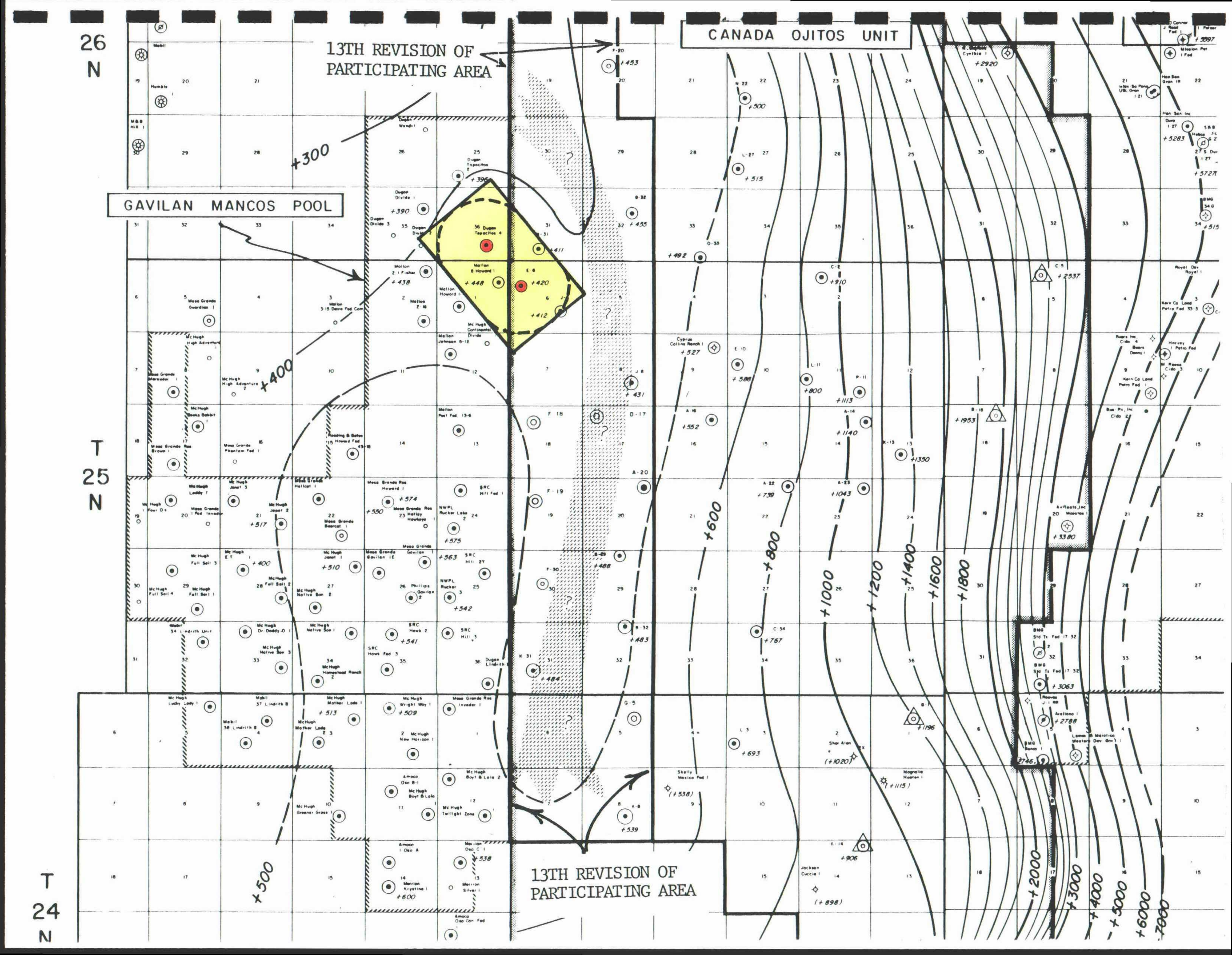
Date: February 13, 1986

See plat on facing page.

Because of the relatively short observation time (.7 day) and small pressure differential of .6#, the calculated pore space, øh, is probably not as definitive of average reservoir conditions as for some of the other tests, although it may more accurately reflect the properties of the high capacity system.

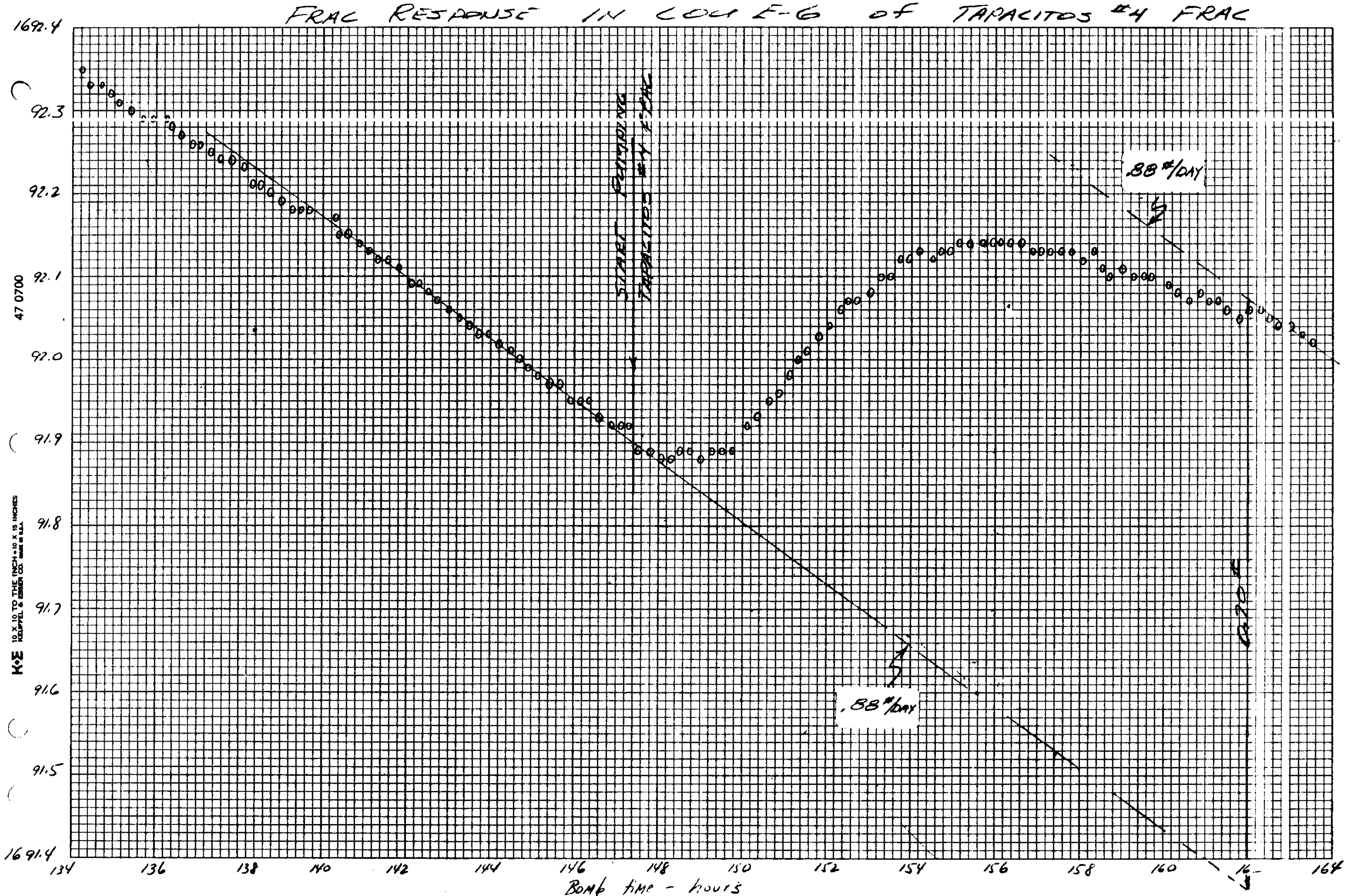
Test Summary of Area and Pore Space:

Area of Investigation at .7 days: approximately 1,200 acres.
Pore space, øh = .47 or 2800 stock tank barrels per acre.
A, B and C zones open.

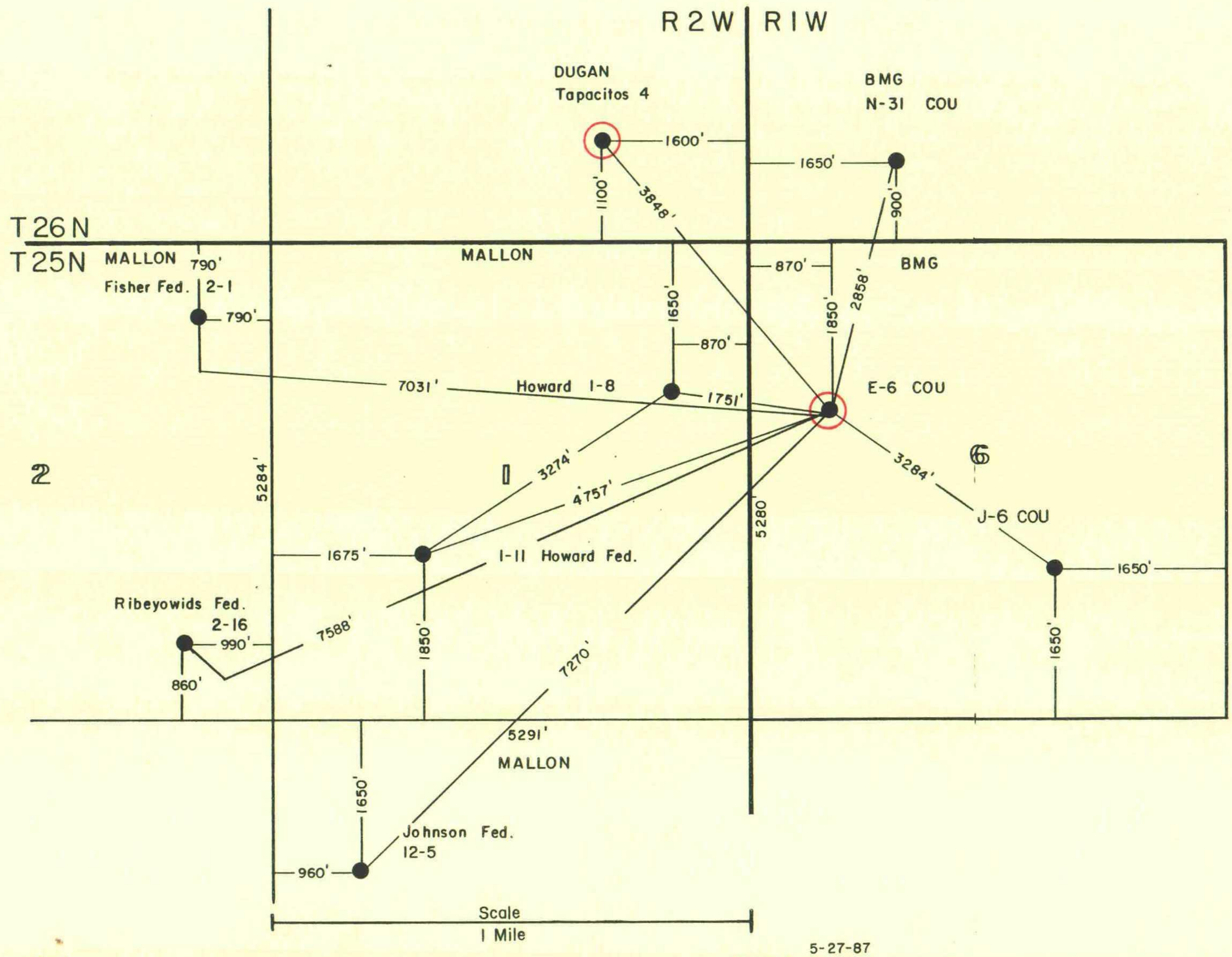


CANADA OJITOS UNIT
GAVILAN MANCOS POOL
13TH REVISION OF PARTICIPATING AREA
13TH REVISION OF PARTICIPATING AREA
T 26 N
T 25 N
T 24 N
+300
+400
+500
+600
+800
+1000
+1200
+1400
+1600
+1800
+2000
+3000
+4000
+5000
+6000
+7000

FRAC RESPONSE IN COOY E-6 of TAPACITOS #4 FRAC



PLAT SHOWING LOCATIONS OF WELLS
IN THE VICINITY OF THE
DUGAN TAPACITOS 4
AND
CANADA OJITOS UNIT E-6
FRAC TREATMENT INTERFERENCE TEST



10/85

5-27-87
Revised: 6-23-86

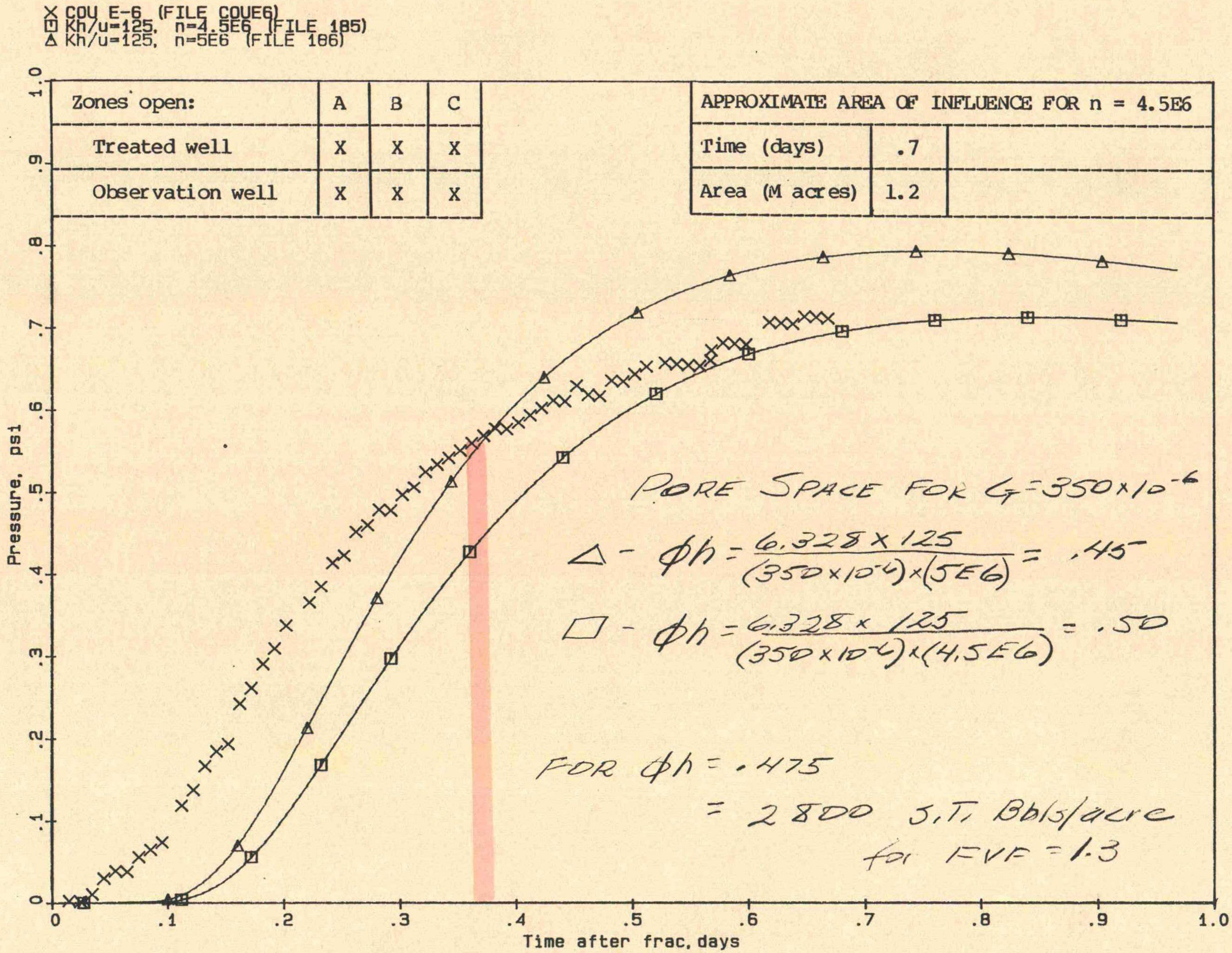
THE COMPUTATION OF PRESSURE RESPONSE TO FRAC TREATMENT
(EI SOLUTION BY SUPERPOSITION)

```
THE VALUE OF Pump Rate Bbls of Fluid/Minute   =  70
THE VALUE OF q ( Bbls of Fluid/Day )          =  100800   BFPD

The Value of Kh/u (Darcy ft/cp) is  125          dc=diffusivity constant
                                                   =6.328K/((a)(c)(u))
The Value of B  ( FVF   ) is  1                    a=porosity,fraction
The Value of r  (  ft   ) is  3848                 c=compressibility
The Value of n  (  dc   ) is  4500000              u=viscosity,cp
The Injection Time (Days) is  .028
The Increment of dt  (1)  is  .03                  IF X > 20 THEN EI(-X) = 0
The Ending day of dt (1)  is  .3
The Increment of dt  (2)  is  .04
The Ending day of dt (2)  is  .7
The Increment of dt  (3)  is  .04
The Ending day of dt (3)  is  1
The Day Shut In           is  .028
The Beginning Pressure    is  0
The Output File name is   is FILE185
```

If $(n)(t)/(rw)^2$ greater than
or equal to 999 then it prints 999

TIME SINCE FRAC START (DAYS)	PRESSURE RESPONSE TO FRAC AT r (PSI)	PRESSURE AT r IF CONTINUOUS PUMPING (PSI)	VALUE OF X IN EI FUNCTION	$(n)(t)/(rw)^2$ rw = 1	rw = 10	rw = 100	rw = 250	$(n)(t)/(r^2)$
0.03	0.00	0.000	29.379	999	999	13	2	0.0085
0.06	0.00	0.000	14.183	999	999	26	4	0.0176
0.09	0.00	0.000	9.348	999	999	40	6	0.0267
0.12	0.01	0.007	6.971	999	999	53	8	0.0359
0.15	0.03	0.034	5.558	999	999	67	11	0.0450
0.18	0.07	0.102	4.621	999	999	80	13	0.0541
0.21	0.12	0.227	3.955	999	999	94	15	0.0632
0.24	0.18	0.419	3.456	999	999	107	17	0.0723
0.27	0.25	0.680	3.069	999	999	121	19	0.0814
0.30	0.31	1.010	2.760	999	999	134	21	0.0906
0.33	0.37	1.404	2.508	999	999	148	24	0.0997
0.37	0.44	2.019	2.235	999	999	166	26	0.1118
0.41	0.50	2.723	2.016	999	999	184	29	0.1240
0.45	0.55	3.501	1.836	999	999	202	32	0.1362
0.49	0.59	4.340	1.686	999	999	220	35	0.1483
0.53	0.63	5.228	1.558	999	999	238	38	0.1605
0.57	0.65	6.154	1.448	999	999	256	41	0.1726
0.61	0.67	7.110	1.353	999	999	274	44	0.1848
0.65	0.69	8.088	1.269	999	999	292	47	0.1969
0.69	0.70	9.083	1.196	999	999	310	50	0.2091
0.73	0.71	10.090	1.130	999	999	328	52	0.2212
0.77	0.71	11.104	1.071	999	999	346	55	0.2334
0.81	0.71	12.121	1.018	999	999	364	58	0.2456
0.85	0.71	13.140	0.970	999	999	382	61	0.2577
0.89	0.71	14.157	0.926	999	999	400	64	0.2699
0.93	0.71	15.171	0.886	999	999	418	67	0.2820
0.97	0.71	16.180	0.850	999	999	436	70	0.2942

RESPONSE TO TAPACITOS 4 FRAC



E

RESPONSE TO FRAC TREATMENT

Treated well: Canada Ojitos Unit F-30 (Sec. 30, T-25N, R-1W)

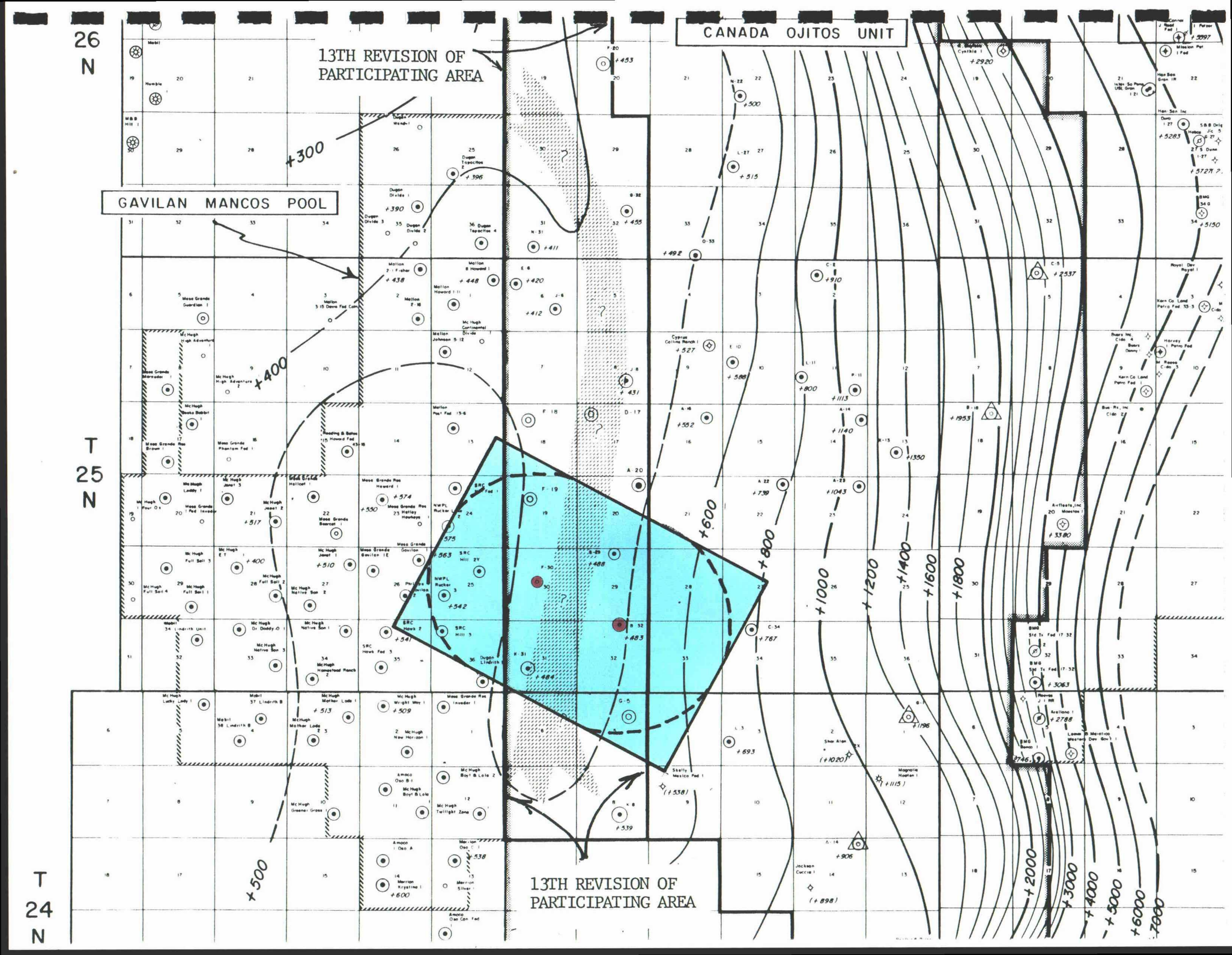
Observation well: Canada Ojitos Unit B-32 (Sec. 32, T-25N, R-1W)

Date: September 4, 1986

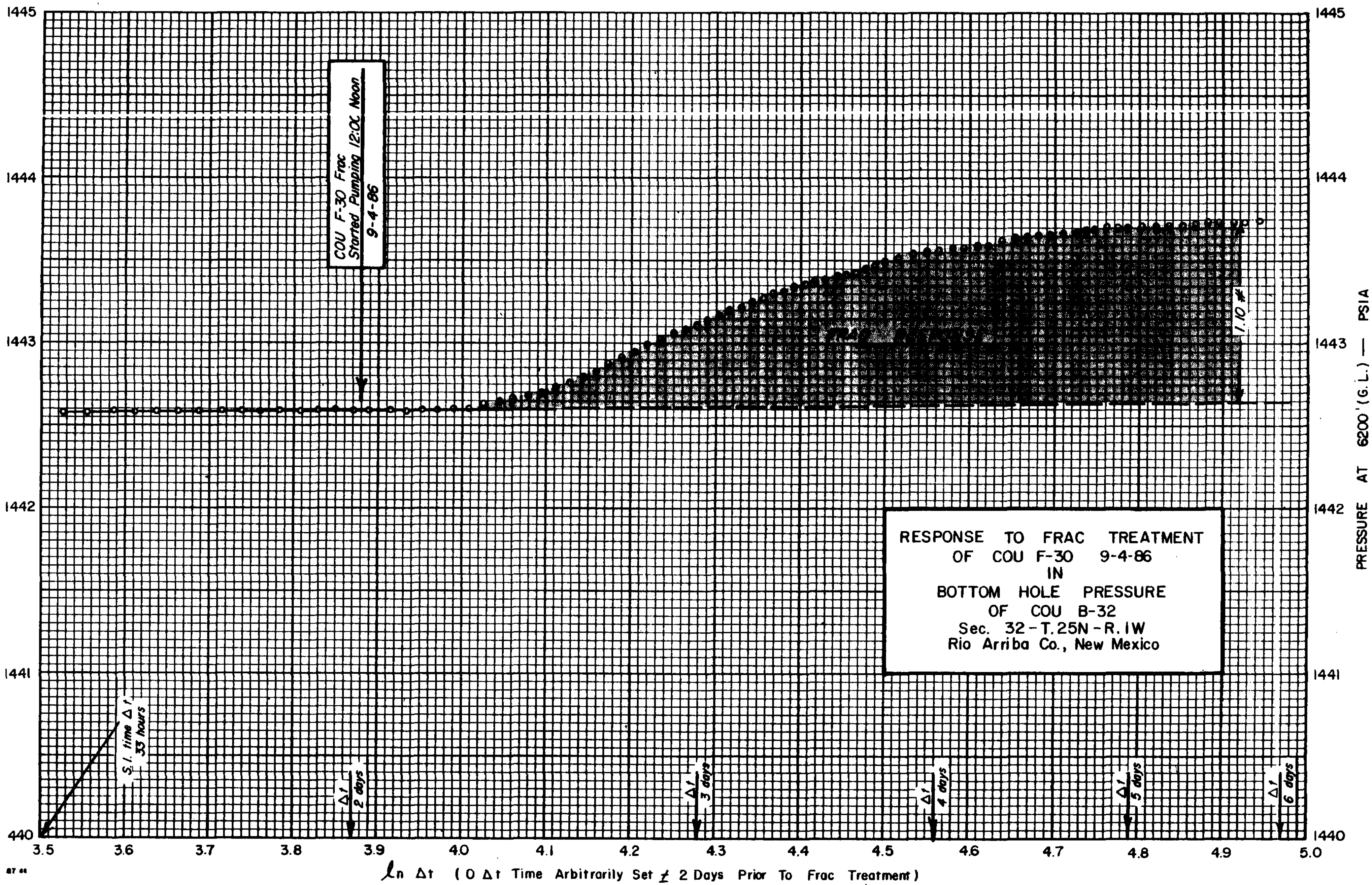
On the facing page is a plat showing the location of the treated well F-30 and the observation well B-32. Also in the same test, interference was measured in the Meridian Hill Federal 2-Y well. Other wells were producing in the vicinity of the Hill 2-Y, however, so that its pressure response was affected, and it is believed that data for this well would not be suitable for analysis.

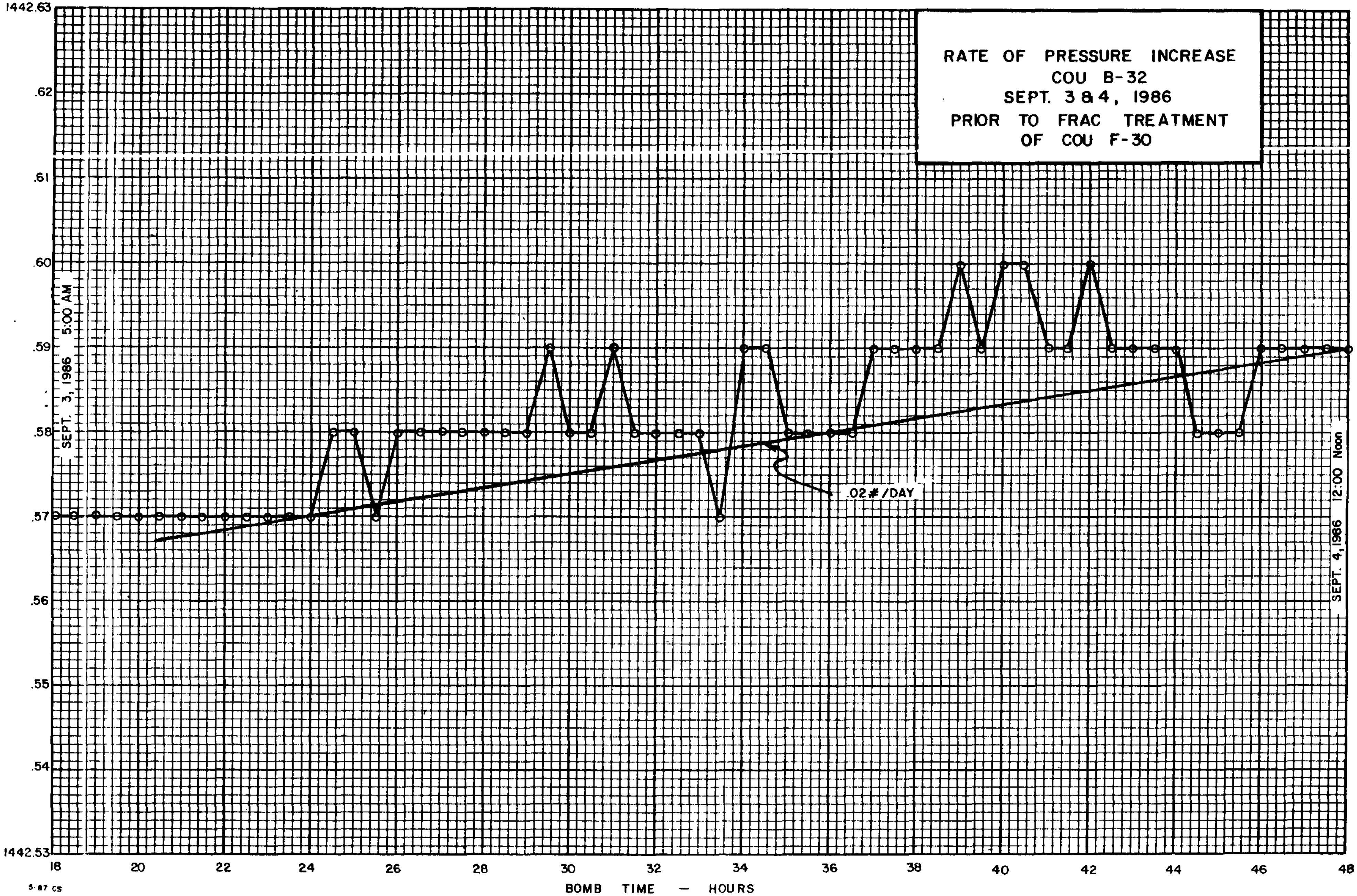
Test Summary of Area and Pore Space:

Area of Investigation at 4 days: approximately 6,000 acres.
Pore space, ϕh = .31 or 1,800 stock tank barrels per acre.
A, B and C zones open.



CANADA OJITOS UNIT
GAVILAN MANCOS POOL
13TH REVISION OF PARTICIPATING AREA
13TH REVISION OF PARTICIPATING AREA
T 26 N
T 25 N
T 24 N
+300
+400
+500
+600
+800
+1000
+1200
+1400
+1600
+1800
+2000
+3000
+4000
+5000
+6000
7000


RESPONSE TO FRAC TREATMENT
OF COU F-30 9-4-86
IN
BOTTOM HOLE PRESSURE
OF COU B-32
Sec. 32-T.25N-R.1W
Rio Arriba Co., New Mexico
COU F-30 Frac
Started Pumping 12:00 Noon
9-4-86
1.10 #
S.I. time Δt
33 hours
Δt 2 days
Δt 3 days
Δt 4 days
Δt 5 days
Δt 6 days
1445
1444
1443
1442
1441
1440
3.5
3.6
3.7
3.8
3.9
4.0
4.1
4.2
4.3
4.4
4.5
4.6
4.7
4.8
4.9
5.0
ln Δt (0 Δt Time Arbitrarily Set ≠ 2 Days Prior To Frac Treatment)
PRESSURE AT 6200'(G.L.) — PSIA


RATE OF PRESSURE INCREASE
COU B-32
SEPT. 3 & 4, 1986
PRIOR TO FRAC TREATMENT
OF COU F-30
1442.63
.62
.61
.60
.59
.58
.57
.56
.55
.54
1442.53
18
20
22
24
26
28
30
32
34
36
38
40
42
44
46
48
BOMB TIME — HOURS
SEPT. 3, 1986 5:00 AM
SEPT. 4, 1986 12:00 Noon
.02 # /DAY
5·87 CS

THE COMPUTATION OF PRESSURE RESPONSE TO FRAC TREATMENT
(EI SOLUTION BY SUPERPOSITION)

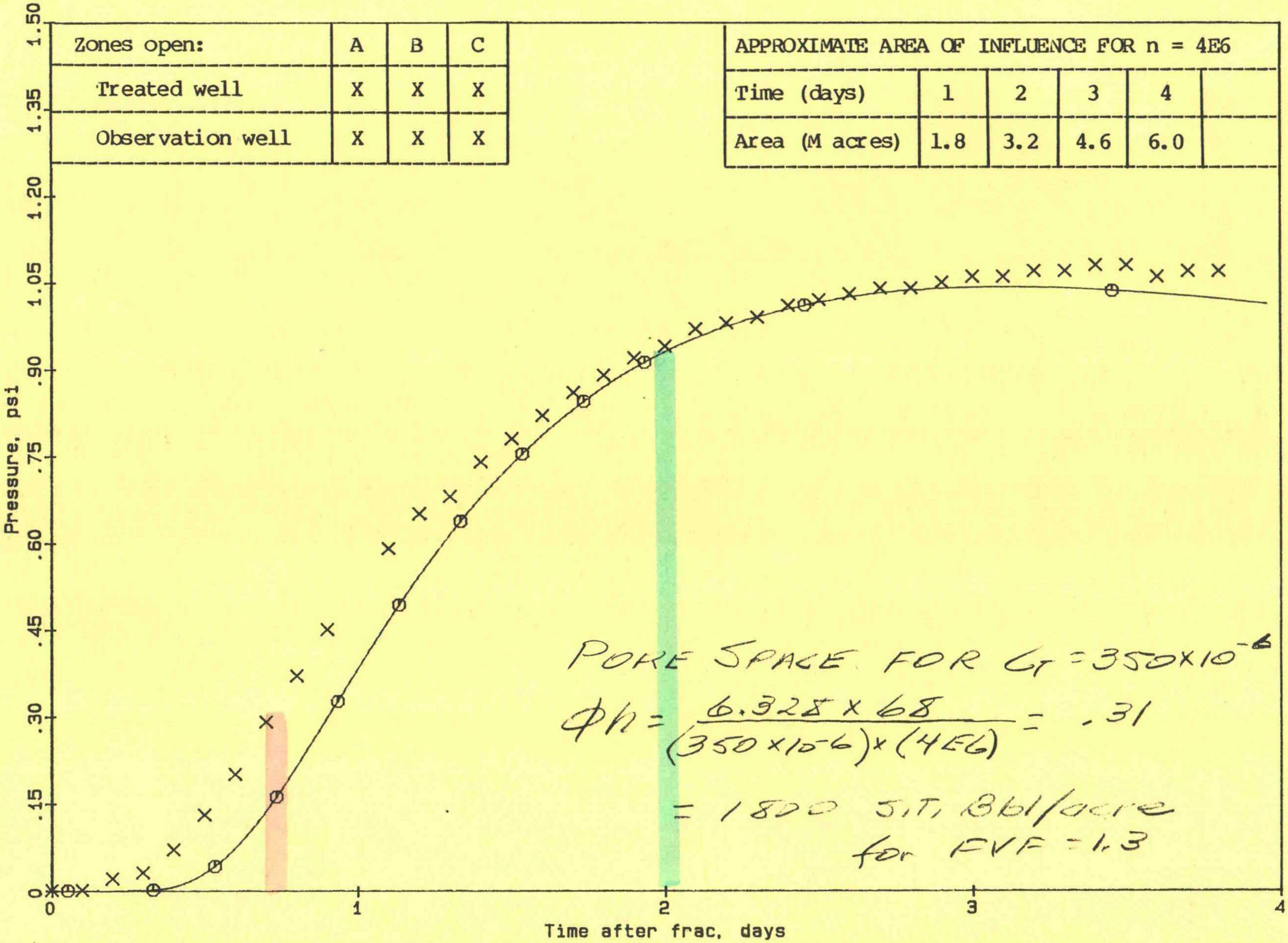
```
THE VALUE OF Pump Rate Bbls of Fluid/Minute   =  107.5
THE VALUE OF q ( Bbls of Fluid/Day )          =  154800   BFPD

The Value of Kh/u (Darcy ft/cp) is  68          dc=diffusivity constant
                                                  =6.328K/((a)(c)(u))
The Value of B  ( FVF   )  is  1                  a=porosity,fraction
The Value of r  (  ft   )  is  7000               c=compressibility
The Value of n  (  dc   )  is  4000000            u=viscosity,cp
The Injection Time (Days)  is  .054
The Increment of dt  (1)   is  .1                 IF X > 20 THEN EI(-X) = 0
The Ending day of dt (1)   is  2
The Increment of dt  (2)   is  .5
The Ending day of dt (2)   is  4
The Increment of dt  (3)   is  1
The Ending day of dt (3)   is  10
The Day Shut In            is  .054
The Beginning Pressure     is  0
The Output File name is    is FILE144
```

If $(n)(t)/(rw)^2$ greater than or equal to 999 then it prints 999

TIME SINCE FRAC START (DAYS)	PRESSURE RESPONSE TO FRAC AT r (PSI)	PRESSURE AT r IF CONTINUOUS PUMPING (PSI)	VALUE OF X IN EI FUNCTION	$(n)(t)/(rw)^2$ rw = 1	$(n)(t)/(rw)^2$ rw = 10	$(n)(t)/(rw)^2$ rw = 100	$(n)(t)/(rw)^2$ rw = 250	$(n)(t)/(r^2)$
0.05	0.00	0.000	56.713	999	999	22	3	0.0044
0.15	0.00	0.000	19.886	999	999	62	10	0.0126
0.25	0.00	0.000	12.057	999	999	102	16	0.0207
0.35	0.00	0.003	8.651	999	999	142	23	0.0289
0.45	0.02	0.025	6.746	999	999	182	29	0.0371
0.55	0.05	0.100	5.528	999	999	222	35	0.0452
0.65	0.10	0.268	4.683	999	999	262	42	0.0534
0.75	0.18	0.564	4.062	999	999	302	48	0.0616
0.85	0.26	1.008	3.586	999	999	342	55	0.0697
0.95	0.34	1.608	3.210	999	999	382	61	0.0779
1.05	0.43	2.366	2.906	999	999	422	67	0.0860
1.15	0.51	3.275	2.654	999	999	462	74	0.0942
1.25	0.58	4.323	2.442	999	999	502	80	0.1024
1.35	0.65	5.500	2.262	999	999	542	87	0.1105
1.45	0.71	6.793	2.106	999	999	582	93	0.1187
1.55	0.77	8.187	1.971	999	999	622	99	0.1269
1.65	0.81	9.672	1.852	999	999	662	106	0.1350
1.75	0.85	11.235	1.746	999	999	702	112	0.1432
1.85	0.89	12.867	1.652	999	999	742	119	0.1513
1.95	0.92	14.557	1.567	999	999	782	125	0.1595
2.05	0.95	16.297	1.491	999	999	822	131	0.1677
2.55	1.02	25.503	1.199	999	999	999	163	0.2085
3.05	1.04	35.106	1.003	999	999	999	195	0.2493
3.55	1.03	44.727	0.862	999	999	999	227	0.2901
4.05	1.01	54.170	0.755	999	999	999	259	0.3309
5.05	0.94	72.181	0.606	999	999	999	323	0.4126
6.05	0.87	88.860	0.506	999	999	999	387	0.4942
7.05	0.80	104.238	0.434	999	999	999	451	0.5758
8.05	0.74	118.433	0.380	999	999	999	515	0.6575
9.05	0.69	131.576	0.338	999	999	999	579	0.7391

RESPONSE TO F-30 FRAC 9/4/86

× COU B-32 (FILE RESPONS.B)
⊖ Kh/u = 68, n = 4E6 (FILE 144)



Zones open:	A	B	C
Treated well	X	X	X
Observation well	X	X	X

APPROXIMATE AREA OF INFLUENCE FOR n = 4E6					
Time (days)	1	2	3	4	
Area (M acres)	1.8	3.2	4.6	6.0	

PORE SPACE FOR $C_T = 350 \times 10^{-6}$

$$\phi h = \frac{6.328 \times 68}{(350 \times 10^{-6}) \times (4E6)} = .31$$

$= 1800$ S.T. Bbl/acre

for FVF = 1.3

F

RESPONSE TO FRAC TREATMENT

Treated well: Canada Ojitos Unit C-34 (Sec. 34, T-25N, R-1W)

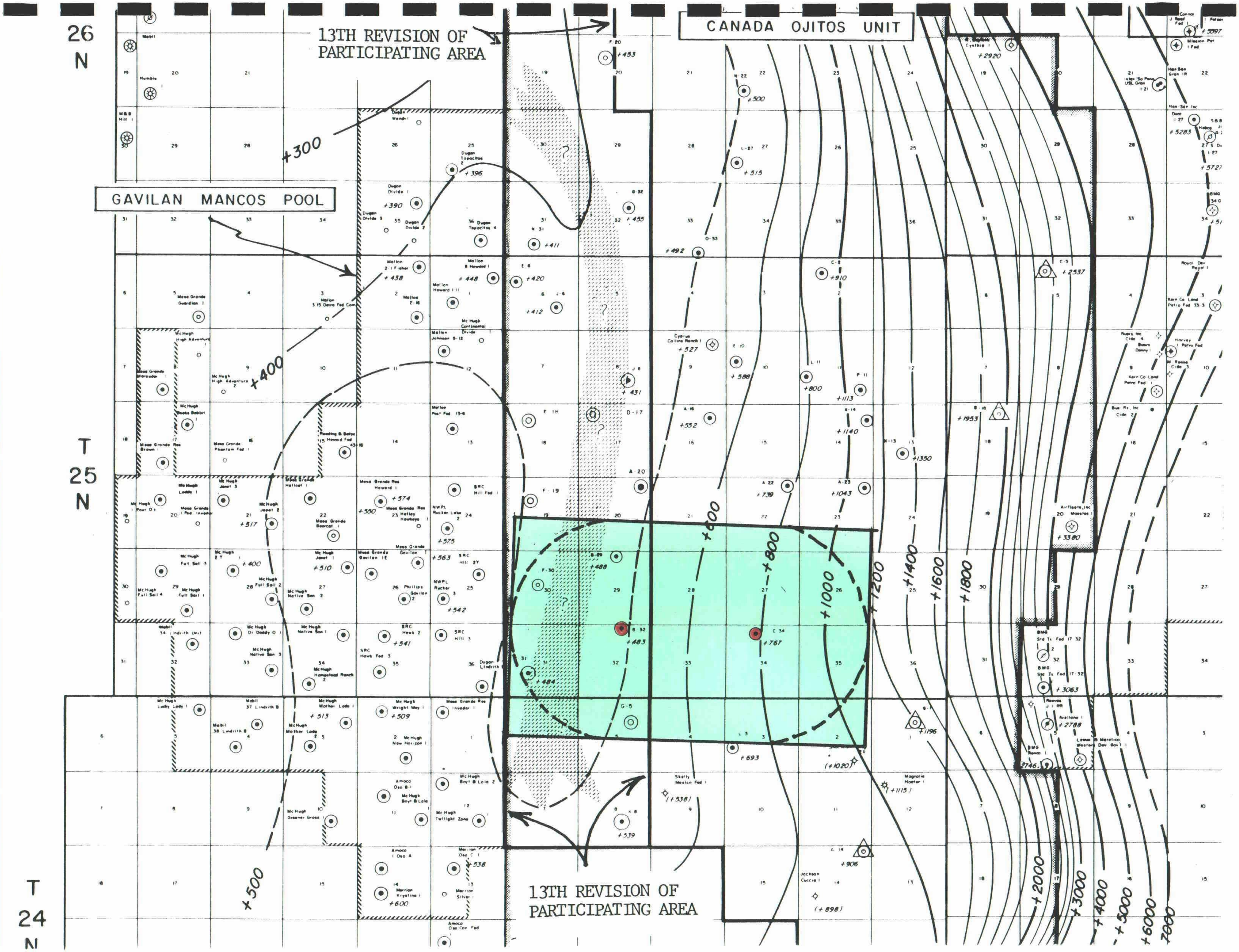
Observation well: Canada Ojitos Unit B-32 (Sec. 32, T-25N, R-1W)

Date: April 23, 1987

See plat on facing page.

Test Summary of Area and Pore Space:

Area of Investigation: approximately 6,500 acres.
Pore space, ϕh = .19 or 1,100 stock tank barrels per acre.
A and B zones open in treated well.



CANADA OJITOS UNIT
GAVILAN MANCOS POOL
13TH REVISION OF PARTICIPATING AREA
13TH REVISION OF PARTICIPATING AREA
T 26 N
T 25 N
T 24 N
+300
+400
+500
+600
+800
+1000
+1200
+1400
+1600
+1800
+2000
+3000
+4000
+5000
+6000
7000

THE COMPUTATION OF PRESSURE RESPONSE TO FRAC TREATMENT
(EI SOLUTION BY SUPERPOSITION)

THE VALUE OF Pump Rate Bbls of Fluid/Minute = 66
THE VALUE OF q (Bbls of Fluid/Day) = 95040 BFPD

The Value of Kh/u (Darcy ft/cp) is 40

dc=diffusivity constant
=6.328K/((a)(c)(u))
a=porosity,fraction
c=compressibility
u=viscosity,cp

The Value of B (FVF) is 1
The Value of r (ft) is 10411
The Value of n (dc) is 4000000
The Injection Time (Days) is .071
The Increment of dt (1) is .1
The Ending day of dt (1) is 2
The Increment of dt (2) is .5
The Ending day of dt (2) is 4
The Increment of dt (3) is 1
The Ending day of dt (3) is 10
The Day Shut In is .071
The Beginning Pressure is 0
The Output File name is is FILE175

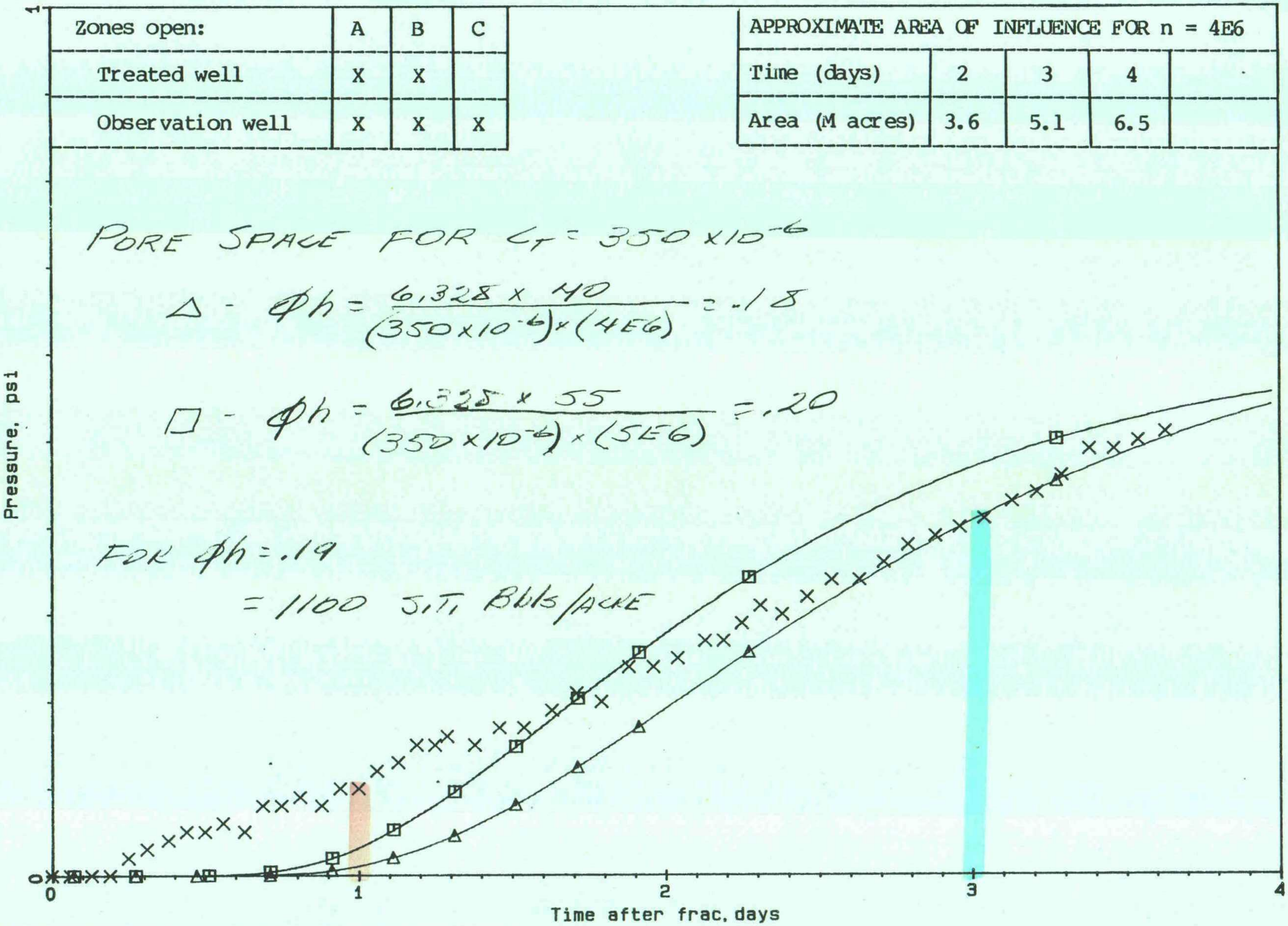
IF X > 20 THEN EI(-X) = 0

If (n)(t)/(rw)² greater than or equal to 999 then it prints 999

TIME SINCE FRAC START (DAYS)	PRESSURE RESPONSE TO FRAC AT r (PSI)	PRESSURE AT r IF CONTINUOUS PUMPING (PSI)	VALUE OF X IN EI FUNCTION	(n)(t)/(rw)² rw = 1	rw = 10	rw = 100	rw = 250	(n)(t)/(r²)
0.07	0.00	0.000	95.413	999	999	28	5	0.0026
0.17	0.00	0.000	39.616	999	999	68	11	0.0063
0.27	0.00	0.000	24.997	999	999	108	17	0.0100
0.37	0.00	0.000	18.260	999	999	148	24	0.0137
0.47	0.00	0.000	14.383	999	999	188	30	0.0174
0.57	0.00	0.000	11.864	999	999	228	37	0.0211
0.67	0.00	0.001	10.096	999	999	268	43	0.0248
0.77	0.00	0.003	8.786	999	999	308	49	0.0285
0.87	0.00	0.008	7.778	999	999	348	56	0.0321
0.97	0.01	0.020	6.977	999	999	388	62	0.0358
1.07	0.02	0.042	6.325	999	999	428	69	0.0395
1.17	0.03	0.077	5.785	999	999	468	75	0.0432
1.27	0.04	0.131	5.330	999	999	508	81	0.0469
1.37	0.06	0.206	4.941	999	999	548	88	0.0506
1.47	0.07	0.307	4.605	999	999	588	94	0.0543
1.57	0.09	0.435	4.312	999	999	628	101	0.0580
1.67	0.12	0.594	4.054	999	999	668	107	0.0617
1.77	0.14	0.784	3.825	999	999	708	113	0.0654
1.87	0.16	1.008	3.621	999	999	748	120	0.0690
1.97	0.19	1.265	3.437	999	999	788	126	0.0727
2.07	0.21	1.555	3.271	999	999	828	133	0.0764
2.57	0.32	3.503	2.635	999	999	999	165	0.0949
3.07	0.42	6.191	2.206	999	999	999	197	0.1133
3.57	0.50	9.470	1.897	999	999	999	229	0.1318
4.07	0.55	13.194	1.664	999	999	999	261	0.1502
5.07	0.62	21.505	1.336	999	999	999	325	0.1871
6.07	0.64	30.416	1.116	999	999	999	389	0.2240
7.07	0.65	39.515	0.958	999	999	999	453	0.2609
8.07	0.64	48.568	0.839	999	999	999	517	0.2979
9.07	0.62	57.446	0.747	999	999	999	581	0.3348

RESPONSE TO C-34 FRAC 4/23/87

× COU B-32 (FILE B32C34)
△ Kh/u = 40, n = 4E6 (FILE 175)
□ Kh/u = 55, n = 5E6 (FILE 181)



Zones open:	A	B	C
Treated well	X	X	
Observation well	X	X	X

APPROXIMATE AREA OF INFLUENCE FOR n = 4E6			
Time (days)	2	3	4
Area (M acres)	3.6	5.1	6.5

PORE SPACE FOR $C_T = 350 \times 10^{-6}$

$$\triangle - \phi h = \frac{6.328 \times 40}{(350 \times 10^{-6}) \times (4E6)} = .18$$

$$\square - \phi h = \frac{6.328 \times 55}{(350 \times 10^{-6}) \times (5E6)} = .20$$

FOR $\phi h = .19$

$= 1100$ S.T. Bbls/ACRE

G

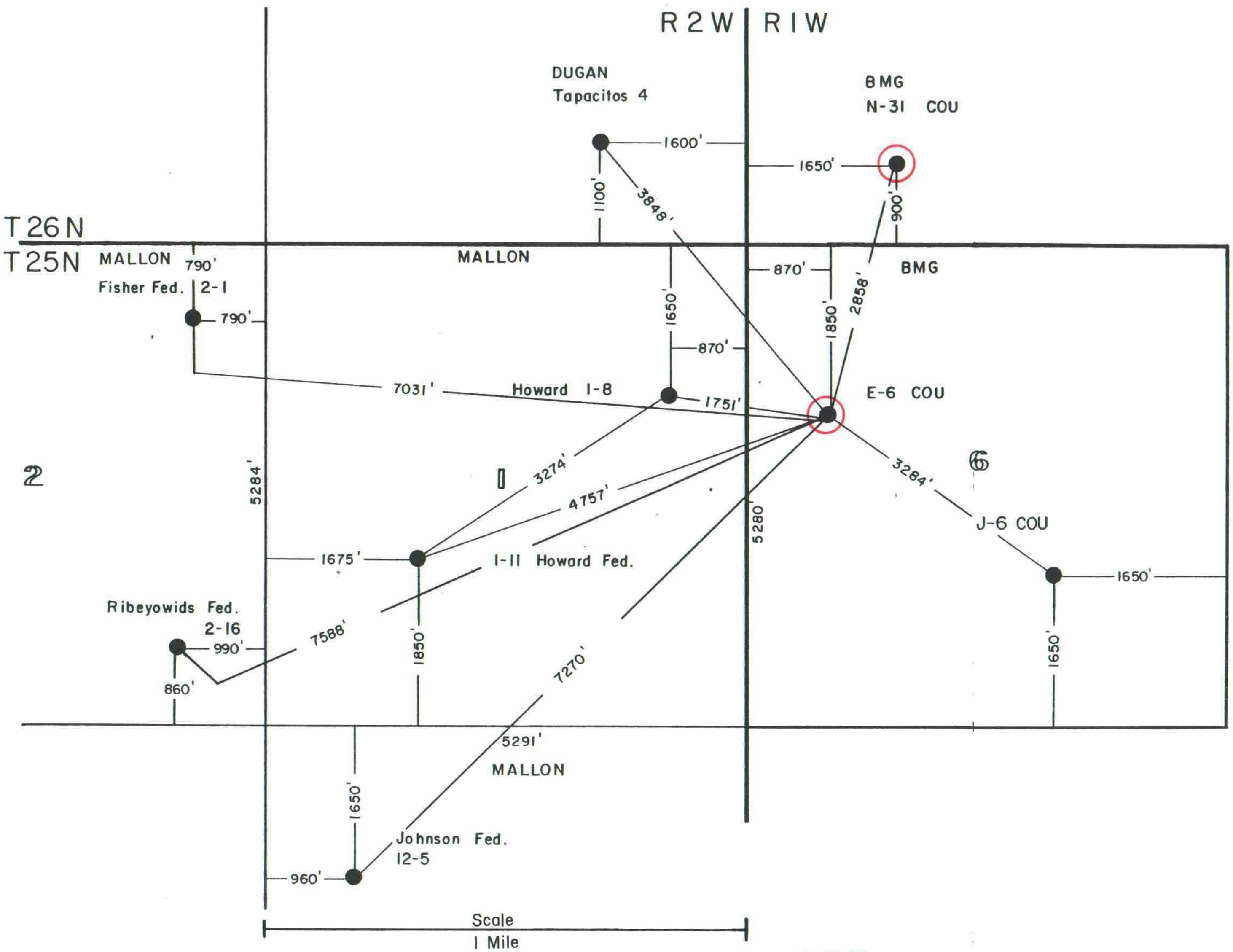
RESPONSE TO FRAC TREATMENT

VARIATION OF CURVE SHAPES WITH INPUT PARAMETERS

It is of interest to compare curve shapes for different values of Kh/u. If, for instance, the value of Kh/u is substantially less than for that in which the curves have been matched, the extreme difference in character is apparent by comparing the curves on the same plot.

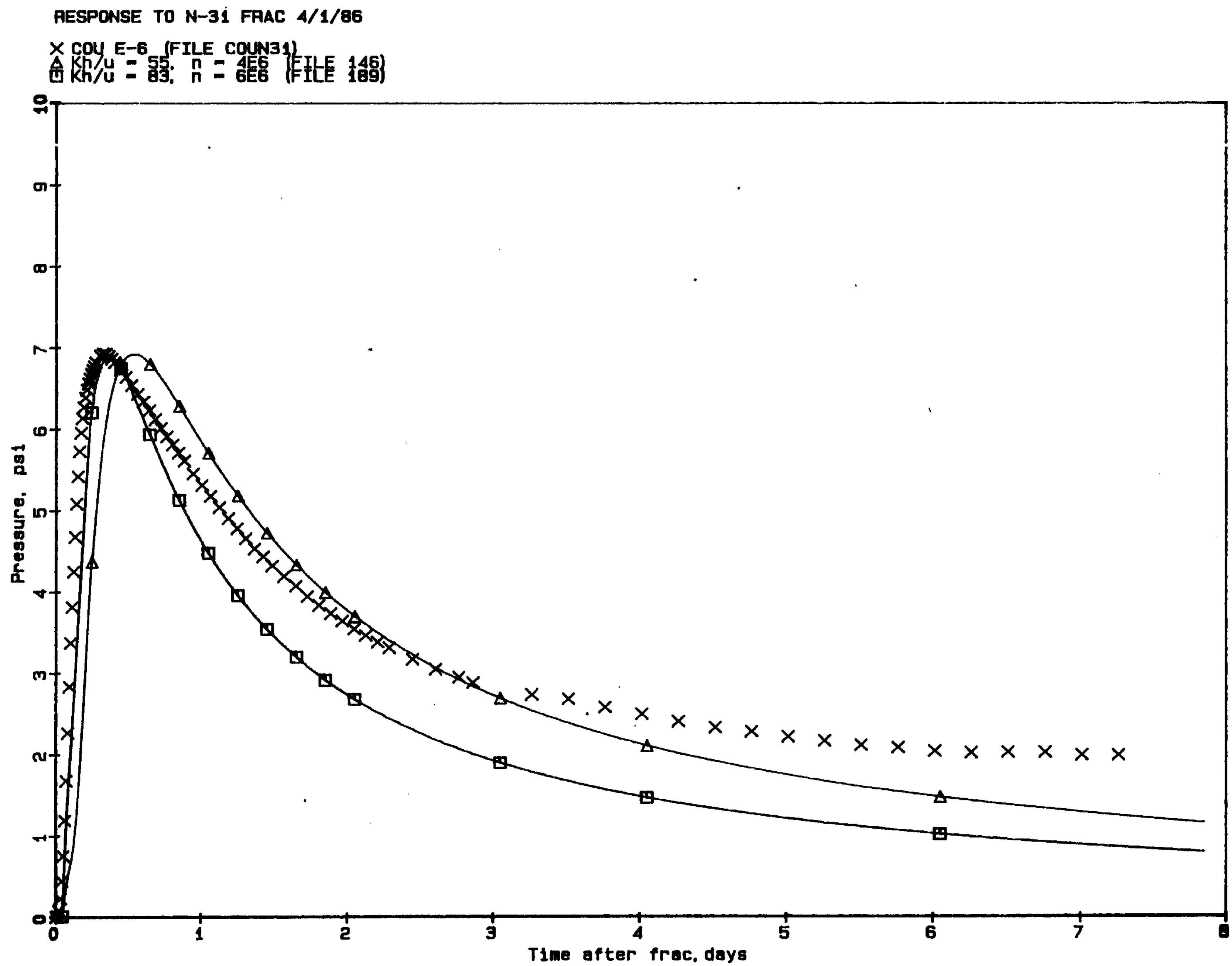
On the following pages a comparison is made with the data for the Canada Ojitos Unit N-31 and Canada Ojitos Unit E-6 frac showing the matched curves and curve which would result if Kh/u is 1 darcy foot and the curve matching is attempted by either matching the peak pressure and letting the data determine the time of the response (the following two gold colored pages) or matching time of the response and letting the data determine the peak pressures (next following tan colored pages).

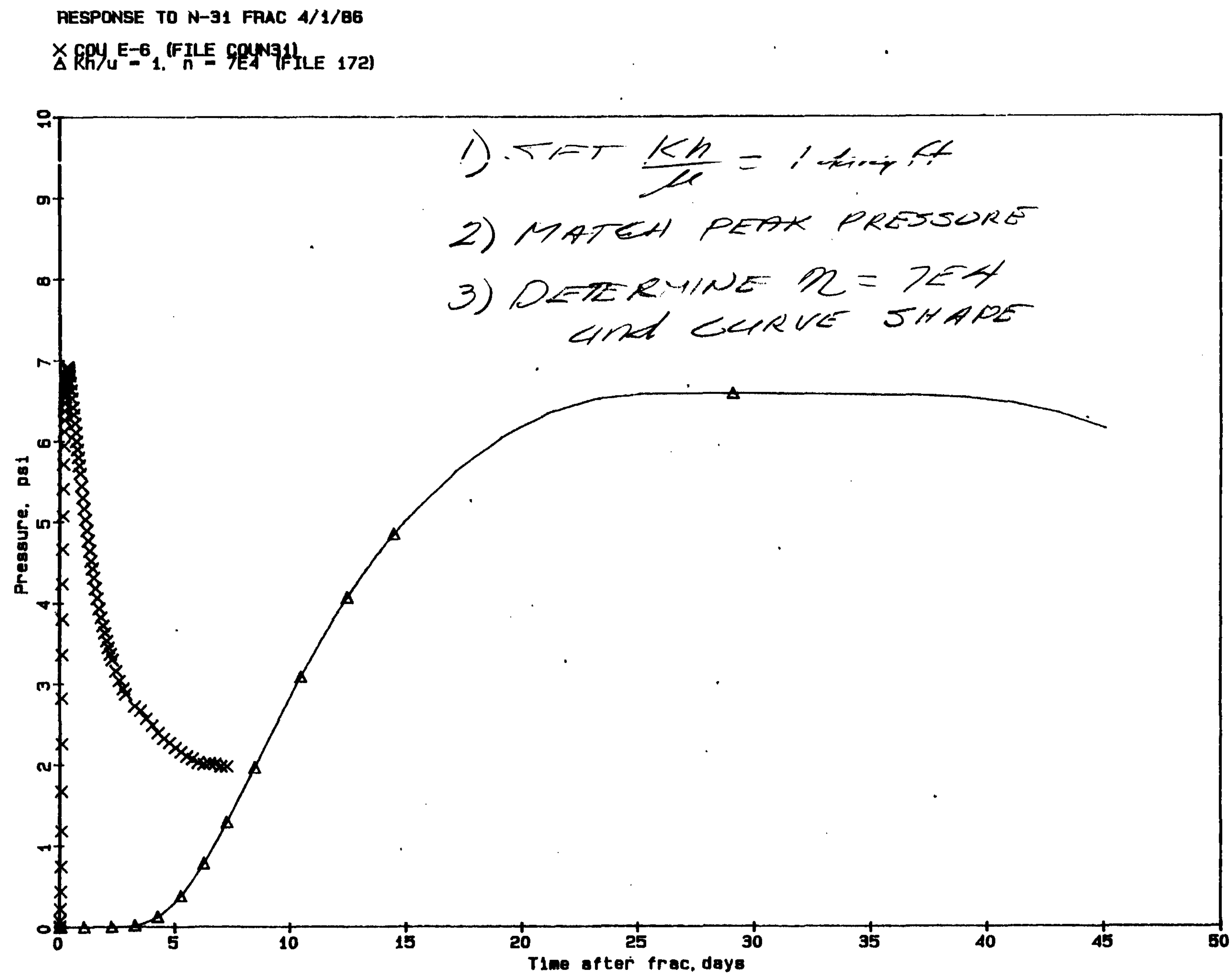
PLAT SHOWING LOCATIONS OF WELLS
IN THE VICINITY OF THE
CANADA OJITOS UNIT N-31
AND
CANADA OJITOS UNIT E-6
FRAC TREATMENT INTERFERENCE TEST



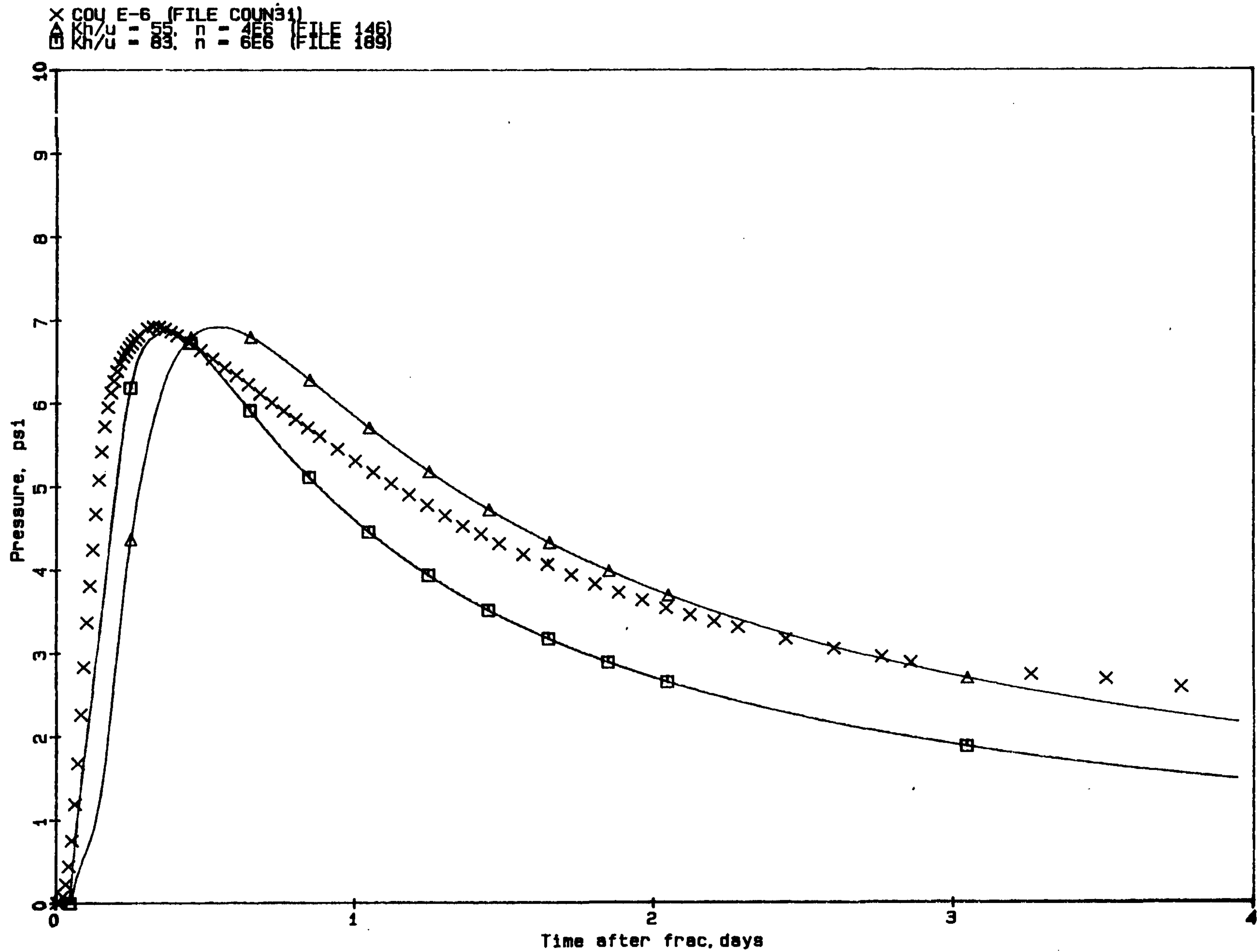
10/85

5-27-87
Revised: 6-23-86

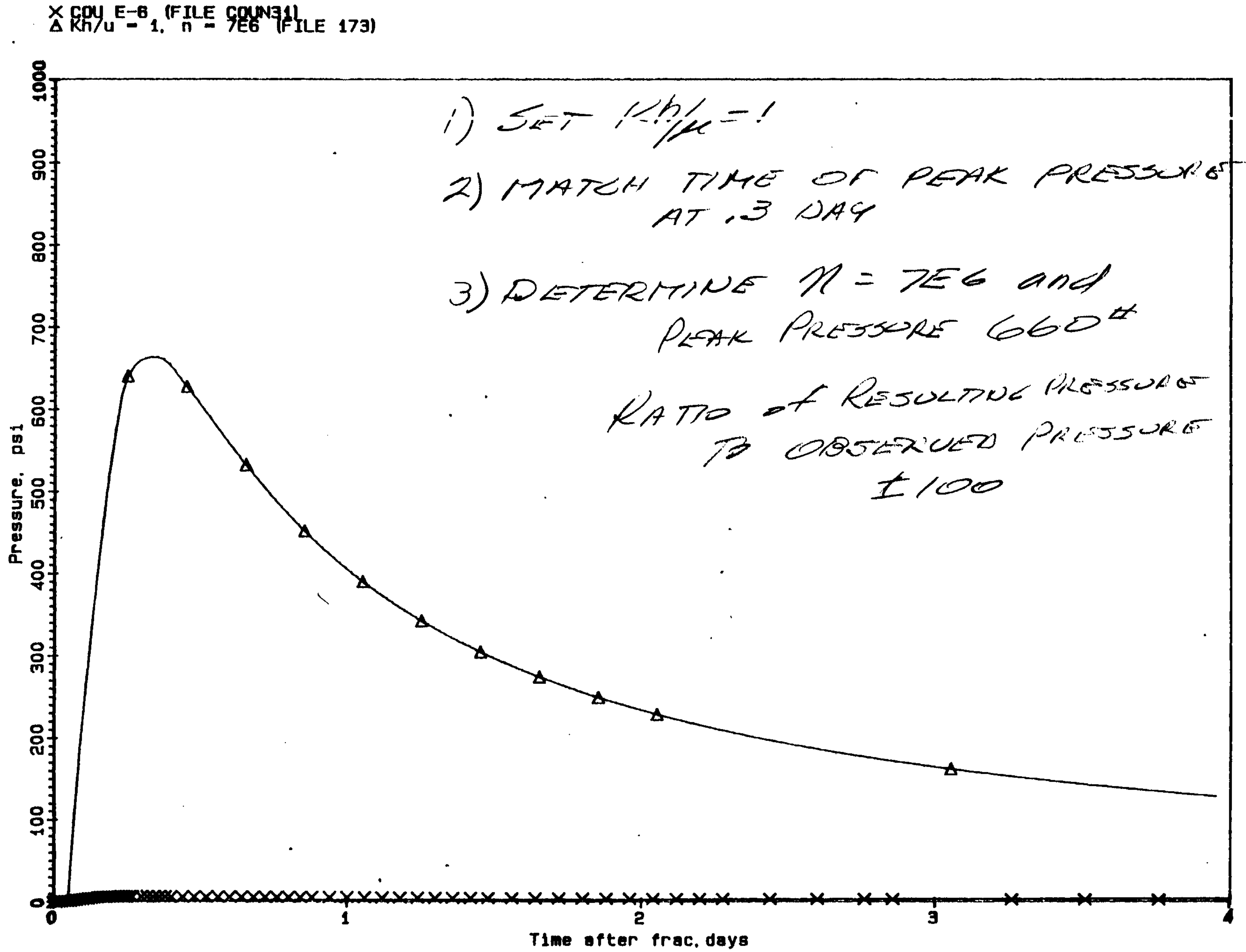

RESPONSE TO N-31 FRAC 4/1/86
× COU E-6 (FILE COUN31)
△ Kh/u = 55, n = 4E6 (FILE 146)
⊡ Kh/u = 83, n = 6E6 (FILE 189)
Pressure, psi
Time after frac, days
0
1
2
3
4
5
6
7
8
9
10


RESPONSE TO N-31 FRAC 4/1/86
× COU E-6 (FILE COUN31)
Δ Kh/u = 1, n = 7E4 (FILE 172)
1) SET Kh/μ = 1 darcy ft
2) MATCH PEAK PRESSURE
3) DETERMINE n = 7E4
and CURVE SHAPE
Pressure, psi
0
1
2
3
4
5
6
7
8
9
10
Time after frac, days
0
5
10
15
20
25
30
35
40
45
50

RESPONSE TO N-31 FRAC 4/1/86



RESPONSE TO N-31 FRAC 4/1/86



RESPONSE TO FRAC TREATMENT
COMPARISON WITH RESERVOIR IN WHICH ONLY 1/10 OF PORE SPACE IS IN HIGH CAPACITY FRACTURE SYSTEM

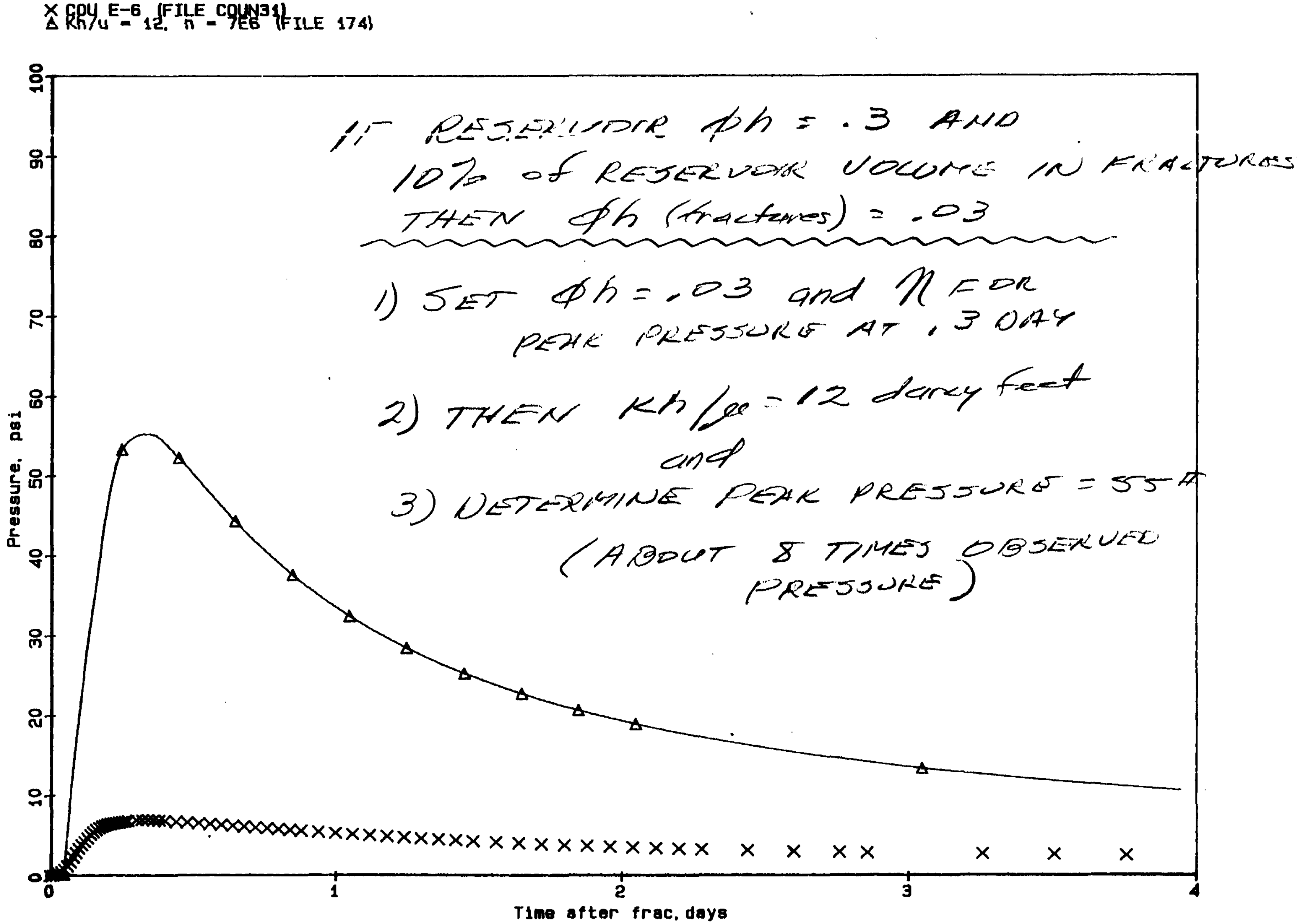
Since the response to a frac treatment should, at early times, be more dependent upon the physical properties of the high capacity fracture system rather than the tight blocks, it is of interest to compare observed data with that which would result for a given proportion of fracture volume to total reservoir volume.

In the example on the facing page, total reservoir pore space, ϕh, is equal to .3. If the pore space of the fractures is 10% of the total, then the fracture pore space would be ϕh equals .03. The comparison is made against the Canada Ojitos Unit N-31/Canada Ojitos Unit E-6 frac treatment of April 1, 1986 and assuming a total compressibility of 350×10^{-6}.

To match peak pressures at the field data point at .3 day requires a diffusivity constant of 7×10^{6}.

The resulting value for Kh/μ is then 12 darcy feet; and the resulting pressure versus time curve for $Kh/u = 12$ and $n = 7 \times 10^{6}$ is shown on the facing page in which the assumed data fails by a factor of about 8 to 1 to match the observed pressures.

RESPONSE TO N-31 FRAC 4/1/86



H

REFERENCES AND APPENDICES

1. John Lee - private communication.

2. "Pressure Interference Effects Within Reservoirs and Aquifers", Thomas D. Mueller and Paul A. Witherspoon, AIME Transactions, Volume 234 (1965), pages 471-474 (blue color, next following).
and
Graph "Error of EI Solution as Dependent on Radius Ratio & Dimensionless Time" (reproduction of Mueller's graph, page 473) (yellow color).

3. John Lee, SPE Textbook Series, Volume I, page 133 (gold color).

4. John Lee, SPE Textbook Series, Volume I, page 90 (green color).

Appendix I: Determination of Pore Volume, ϕh from Pressure Response to Frac Treatment using EI Solution (by Superposition) (pink color).

Appendix II: Determination of Koh (3 pages, white).
and graph (blue color).

Pressure Interference Effects Within Reservoirs and Aquifers

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ABSTRACT

For the case of an infinite radial system operating at constant terminal rate, the reservoir engineer often uses the "point source" solution of the diffusivity equation to study pressure interference effects. At early times and at short distances from the inner boundary these solutions are invalid. The amount of error is often not precisely defined because of mathematical difficulties. Work presented here shows that, if dimensionless time is defined appropriately, previous solutions of the pressure equation can be displayed as a family of curves on one chart. These solutions include the point source solution (referred to in the field of hydrology as the Theis solution) and other solutions obtained with digital computer methods. With these curves, an exact evaluation of the pressure drop within a reservoir or an aquifer can be made by the engineer. Examples of field problem solutions are presented. In most reservoirs the error involved when the Theis solution is employed is often negligible; whereas, in the calculation of interference effects in an aquifer, a substantial error can occur through such an approach.

INTRODUCTION

Flow equations are used in petroleum engineering to study the behavior of individual wells and reservoirs. In the case of wells, the pressure response at the wellbore face is the major point of interest; whereas, in the case of reservoirs, the pressure response at the interface of the aquifer boundary is sought. To aid in such studies, the flow equations have been solved in terms of the behavior at these two inner boundaries.

Only limited work has been published in regard to the pressure conditions away from these points, i.e., within the reservoir or aquifer. Theis[1] and Mortada[2] are among the few who have reported on this problem. The Theis approach employs the exponential integral and is valid for pressure conditions that occur some distance away from the flow disturbance. It is derived from the concept of a point source, as opposed to a flow across some finite area. The Mortada results, on the other hand, are valid at all points within the reservoir or aquifer. They are presented in terms of dimensionless ratios of the radius where the pressure is desired to the radius where the flow rate is measured. Their main use, in the past, has been in aquifer studies. The published results are presented in the form of graphs that are limited to a maximum radius ratio of 64. These graphical results are cumbersome to interpolate at non-integral radius ratios, so that one may be forced to utilize a rather involved analytical expression presented by Mortada.

BASIC EQUATIONS

The solutions of Mortada and Theis are both based on the diffusivity equation as applied to the case of an infinite radial system subject to a constant terminal rate. The equation is obtained by combining the material balance equation with Darcy's flow equation. The assumptions implicit in the use of this equation are as follows: (1) a single fluid is present that occupies the entire pore volume; (2) the reservoir is horizontal, homogeneous, uniform in thickness, and of infinite radial extent; (3) compressibility and viscosity of the fluid remain constant at all pressures; and (4) fluid density obeys the equation

$$\rho = \rho_o \exp - c(p_o - p) \quad . \quad . \quad . \quad (1)$$

Using the diffusivity equation in situations where the above conditions do not hold will result in errors. These errors (not discussed here) but only the errors which arise in the solution of the equation itself.

The diffusivity equation for the homogeneous reservoir conditions cited above can be written in cylindrical coordinates, as

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} = \frac{\phi \mu c}{k}\frac{\partial p}{\partial t} \quad . \quad . \quad . \quad (2)$$

To obtain a dimensionless equation, so a single solution can be used for applications of different porosity, permeability and fluid properties, the following transformations are usually made:

$$p_D = \frac{2\pi kh(p_2 - p_1)}{q\mu}, \quad . \quad . \quad . \quad (3)$$

$$r_D = r/r_w \quad , \quad . \quad . \quad . \quad (4)$$

$$t_D = \frac{kt}{\phi \mu c\, r_w^2} \quad . \quad . \quad . \quad (5)$$

After these transformations are made, Eq. 3 can be written in dimensionless form, as

$$\frac{\partial^2 p_D}{\partial r_D^2} + \frac{1}{r_D}\frac{\partial p_D}{\partial r_D} = \frac{\partial p_D}{\partial t_D} \quad . \quad . \quad . \quad (6)$$

MORTADA SOLUTION

One solution of Eq. 6 has been given by Mortada,[2]

Original manuscript received in Society of Petroleum Engineers office Nov. 8, 1964. Revised manuscript received March 12, 1965. Paper presented at SPE California Regional Meeting held in Los Angeles, Nov. 5-6, 1964.

[1]References given at end of paper.

where he presented dimensionless pressure drop as a function of dimensionless time. His graphical results are reproduced in Fig. 1. The dimensionless time is given in terms of the radius at the inner boundary, i.e., the wellbore or the aquifer boundary. Results of the dimensionless pressure drop vs dimensionless time are given at the following radius ratios: 1, 2, 4, 8, 16, 32 and 64, although results at much higher ratios are available from Mortada. As will be shown there is no need to carry out such determinations for radius ratios above 20.

van Everdingen and Hurst[2] have also presented results of the dimensionless pressure drop at the wellbore interface ($r_D = 1$) as a function of dimensionless time defined in the same manner as above. Their results correspond to Mortada results at the same $r_D = 1$. More recently, Driscoll has also used the concept of dimensionless pressure vs dimensionless time at various radius ratios.[4]

THEIS SOLUTION

The mathematical formulation of the point source solution and its resultant exponential integral are due to Lord Kelvin.[2,3] Theis, however, is the first, to our knowledge, to demonstrate how the point source solution could be employed in the analysis of non-steady-state flow problems.[1] In recognition of his early work, the exponential integral solution is normally referred to in the field of hydrology as the Theis solution, and that term is adopted here.

In this solution, the variable X is defined as a dimensionless quantity inversely related to time. X is the independent variable in the Theis solution, and the integral value or dependent variable is related to the dimensionless pressure drop. The definitions of the dependent and independent variables are compared with those of Mortada and van Everdingen and Hurst in Table 1. The Theis solution of the exponential integral is shown in Fig. 2.

If we alter the definition of dimensionless time given in Eq. 5 to be based on any radius in the infinite system, we then have

$$t_D = \frac{kt}{\phi \mu c r^2} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (7)$$

The dimensionless time of Mortada is related to that of Eq. 7, by

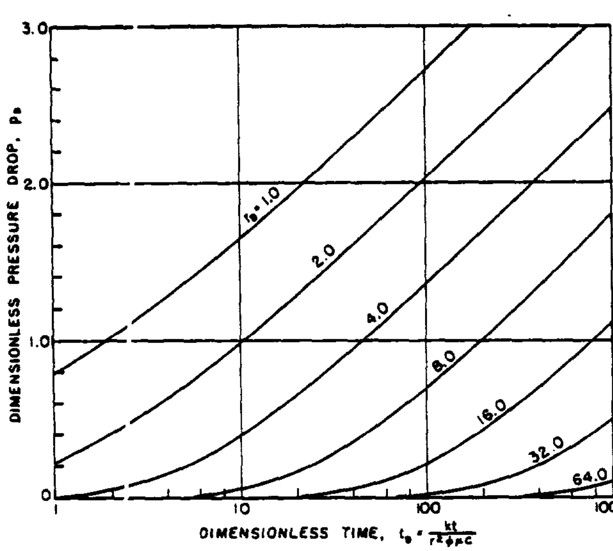

FIG. 1—MORTADA'S POINT SOURCE SOLUTION.

TABLE 1—COMPARISON OF DEPENDENT AND INDEPENDENT VARIABLES

	Dimensionless Independent Variable	Dimensionless Dependent Variable	Dimensioned Pressure Drop
Theis	$X = \frac{r^2 \phi \mu c}{4kt}$	$Ei(-X)$	$\frac{q\mu}{4\pi kh} Ei(-X)$
Mortada, and van Everdingen and Hurst	$t_D = \frac{kt}{\phi \mu c r_w^2}$	Δp_D	$\frac{q\mu}{2\pi kh} \Delta p_D$

$$t_D \text{ (Eq. 7)} = \frac{t_D(\text{Mortada})}{r_D^2} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (8)$$

From Table 1, it can also be seen that, with reference to the Theis solution,

$$t_D \text{ (Eq. 7)} = \frac{1}{4X} \, , \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (9)$$

and

$$\Delta p_D = \frac{Ei(-X)}{2} \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad . \quad (10)$$

Fig. 3 represents the Theis results of Fig. 1 with the definitions of dimensionless time and dimensionless pressure as given in Eqs. 9 and 10, respectively. By adjusting the dimensionless time of the Mortada solutions in accordance with Eq. 8, it is apparent that the array of curves on Fig. 1 becomes a family of curves on Fig. 3 that converge on the Theis solution. Other radius ratios not given in Mortada's work were obtained from the digital calculations performed to obtain the results given by Mueller.[5]

It can be seen on Fig. 3 that, for all radius ratios greater than 20, the Theis solution adequately gives the pressure drop after any practical time.

This can be further demonstrated by the results presented in Fig. 4, which shows the relationship between the per cent error one would get in using the Theis solution for various radius ratios in place of the exact solution. It will be seen that, after a dimensionless time of 50, the Theis solution can be used with an error of only 1 per cent for all radius ratios. This, of course, is also evident from the convergence of all curves onto essentially a single line on Fig. 3. Any combination of radius ratio and dimensionless time that falls to the right of the 1 per cent line on Fig. 4 will have an error of less than 1 per cent. Correspondingly, any combination falling to the right of the 0.1 per cent line will have an error of less than 0.1 per cent.

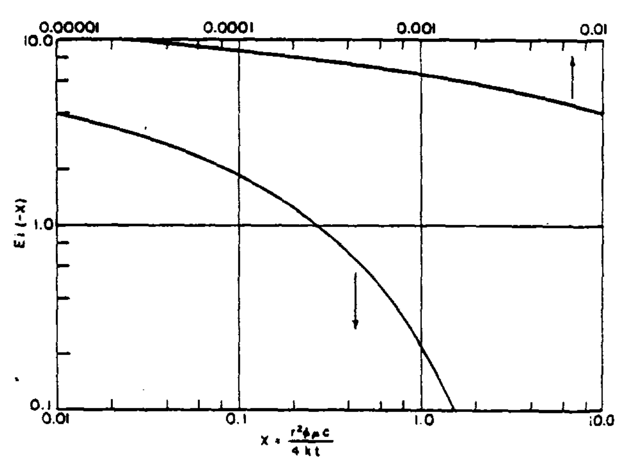

FIG. 2—THEIS' SOLUTION OF EXPONENTIAL INTEGRAL.

NUMERICAL EXAMPLES

EXAMPLE A

To demonstrate the use of Figs. 3 and 4, let us consider the following situation. We wish to know the pressure drop in an aquifer at a point that is 50,000 ft away from the center of a reservoir having an equivalent radius

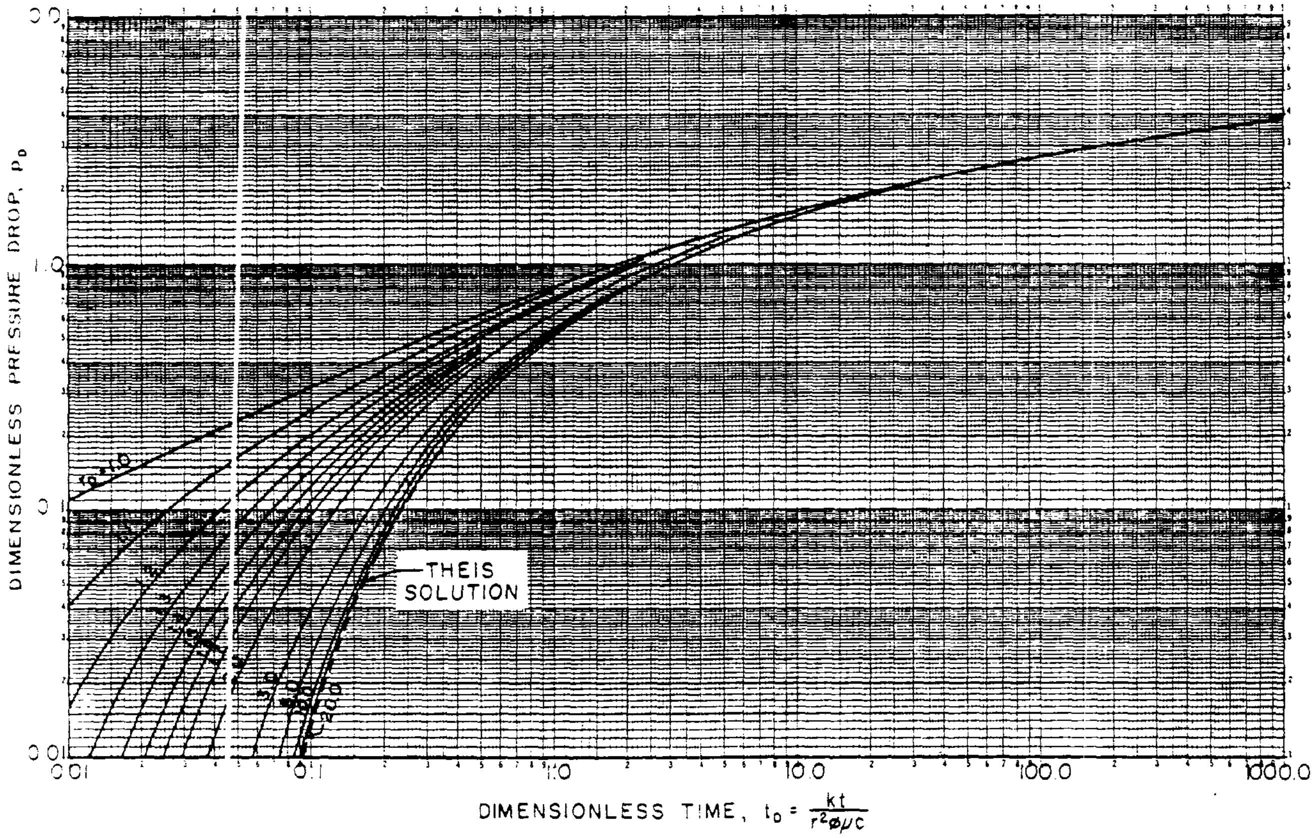

Fig. 3—Complete Solution for Infinite Radial System.

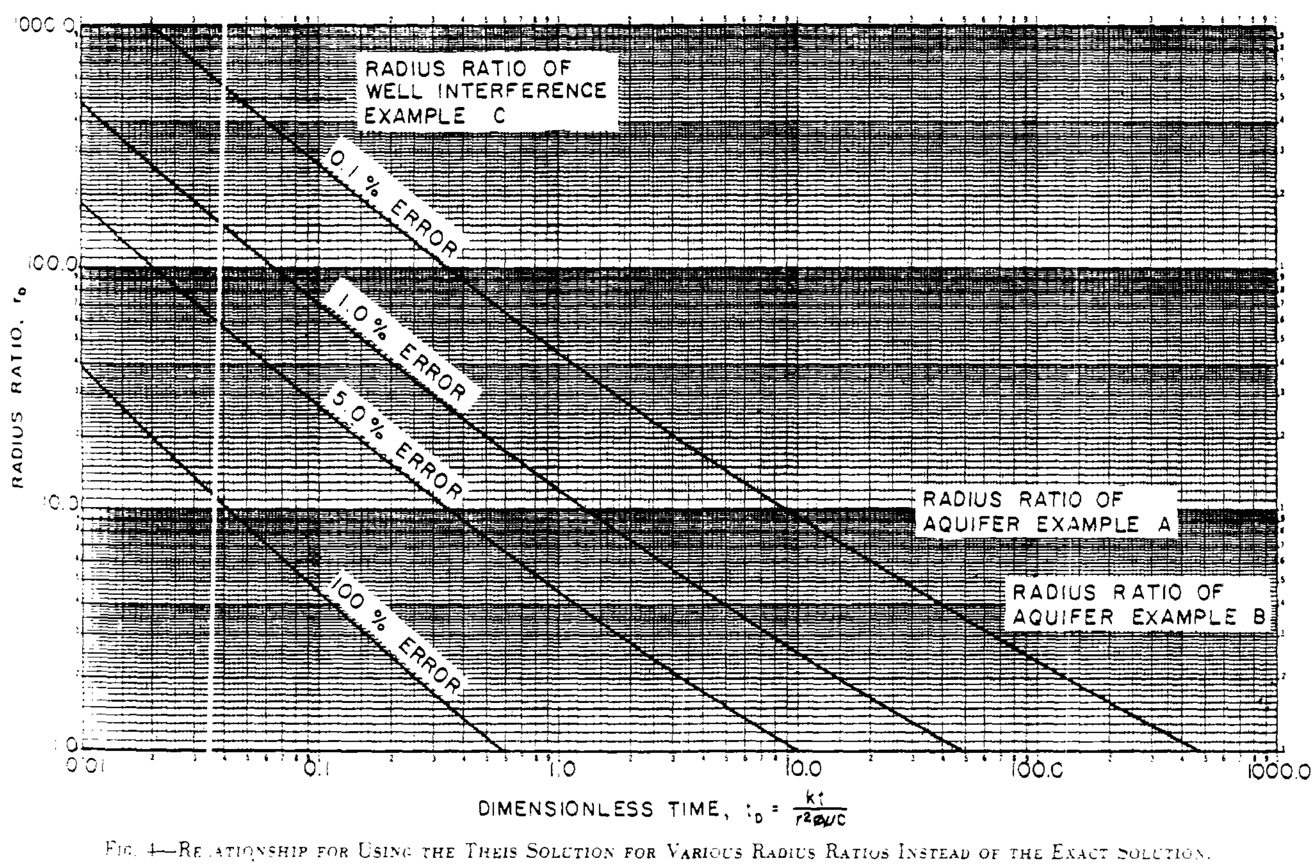

Fig. 4—Relationship for Using the Theis Solution for Various Radius Ratios Instead of the Exact Solution.

of 5,000 ft. The aquifer and associated water have the following properties:

$$k = 356 \text{ md, or 2 perms}$$
$$1 \text{ perm} = 1 \text{ cu ft—cp/day-ft-psi}$$
$$\phi = 0.2 \text{ per cent}$$
$$c = 4 \times 10^{-6} \text{ psi}^{-1}$$
$$\mu = 1 \text{ cp}.$$

From these properties, the dimensionless time can be found from Eq. 7:

$$t_D = \frac{kt}{\phi \mu c r^2} = \frac{2t}{0.2 \times 1 \times 4 \times 10^{-6} \times 50{,}000^2}$$

$$t_D = 0.001\, t$$

After 100 days, $t_D = 0.1$, for which $\Delta p_D = 0.0165$ at $r_D = 10$. Fig. 4 shows that an error of about 50 per cent would result if the Theis solution were used instead of the exact solution.

To translate this into more meaningful terms, assume that $h = 56.2$ ft and $q = 1{,}256$ B/D. From Eq. 3, we find,

$$\Delta p = \frac{q\mu \Delta p_D}{2\pi kh} = \frac{1{,}256 \times 1 \times 5.62 \times 0.0165}{6.28 \times 2 \times 56.2}$$

$$\Delta p = 0.165 \text{ psi}.$$

This quantity is much less than can be detected with field instruments. It can be concluded that, although the use of the Theis curve would result in a large percentage error, the absolute magnitude would be small. Continuing this example further, after 1,000 days, $t_D = 1$ and $\Delta p_D = 0.53$ or $\Delta p = 5.3$ psi. According to Fig. 4, using the Theis solution would introduce an error of about 2 per cent.

EXAMPLE B

Let us examine another aquifer situation at a smaller radius ratio to determine if the error that would result from the Theis solution would be substantial. We wish to know the pressure drop at a point in an aquifer 10,000 ft from the center of a reservoir with an equivalent radius of 2,500 ft. Assume the following conditions:

$$k = 63.2 \text{ md, or 0.4 perms}$$
$$\phi = 0.1 \text{ per cent}$$
$$c = 4 \times 10^{-6} \text{ psi}^{-1}$$
$$\mu = 1 \text{ cp}$$
$$r_D = 10{,}000/2{,}500 = 4$$
$$t_D = \frac{0.4\, t}{0.1 \times 1 \times 4 \times 10^{-6} \times 10{,}000^2} = 0.01t.$$

From Fig. 4, at all times greater than $t = 490$ days, the Theis curve can be used and the error will be 1 per cent or less. However, for times less than $t = 120$ days, the errors would exceed 5 per cent; and as indicated on Fig. 4 by the location of the 100 per cent error line, these errors would increase rapidly at lower values of time. The absolute magnitude would depend on the other aquifer parameters.

EXAMPLE C

The Theis solution can be used for points in the reservoirs of large radius ratios with little or no error. Let us examine the situation where the distance between wells is 250 ft, and the well radius is 0.5 ft. Assume the following conditions:

$$k = 158 \text{ md, or 1 perm}$$
$$\phi = 0.2 \text{ per cent}$$
$$c = 8 \times 10^{-6} \text{ psi}^{-1}$$
$$\mu = 0.4 \text{ cp}$$
$$t_D = \frac{1\, t}{0.2 \times 0.4 \times 8 \times 10^{-6} \times 250^2} = 25t.$$

From Fig. 4, it can be seen that at $r_D = 500$, the Theis solution can be used with an error of 0.1 per cent or less for all values of $t_D > 0.045$. This is equivalent to about 2 minutes. For all practical examples where the radius ratio is large, the Theis solution can be used with confidence.

CONCLUSIONS

1. Solutions for the diffusivity equation for the infinite radial case at constant terminal rate are presented in the form of graphs of dimensionless pressure drop vs dimensionless time for radius ratios from 1 to infinity.

2. For radius ratios of 20 or above, the Theis, or point source, solution can be used with little or no error for most practical situations. A chart is presented where one can determine the order of the errors that will result through use of the Theis solution.

3. In aquifer studies, it might be necessary to use the new solutions of the diffusivity equation presented here for low radius ratios. The absolute magnitude of the pressure effects with low ratios and small times might, however, be insignificant.

4. In well interference tests, the Theis solution can be used for all practical lengths of time, and at all normal well spacings, without introducing errors greater than 0.1 per cent.

NOMENCLATURE

c = compressibility of fluid, psi^{-1}
h = reservoir thickness, ft
k = permeability, md, (1 perm = 158 md)
p = pressure, psia
p_D = dimensionless pressure
p_o = reference pressure, psia
p_1 = initial pressure at some given point, psia
p_2 = pressure at some given point after an elapse of time, psia
q = constant flow rate at well, B/D
r = radial distance, ft
r_D = dimensionless radius
r_w = wellbore radius, ft
t = time, days
t_D = dimensionless time
X = independent variable in Theis solution
μ = fluid viscosity, cp
ρ = fluid density at pressure p, lb/cu ft
ρ_o = fluid density at pressure p_o, lb/cu ft
ϕ = porosity

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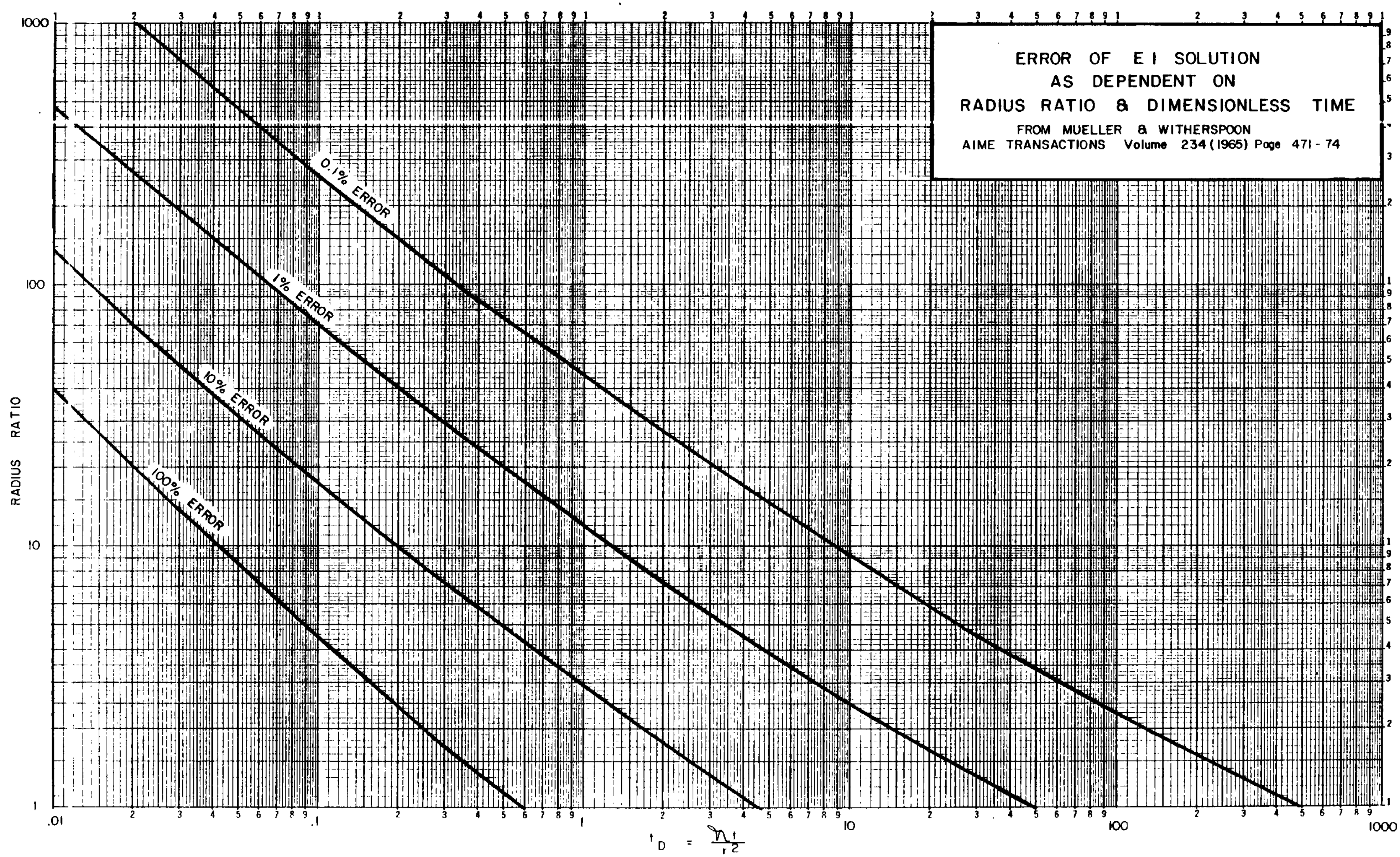
ERROR OF E I SOLUTION
AS DEPENDENT ON
RADIUS RATIO & DIMENSIONLESS TIME
FROM MUELLER & WITHERSPOON
AIME TRANSACTIONS Volume 234 (1965) Page 471 - 74
0.1% ERROR
1% ERROR
10% ERROR
100% ERROR
RADIUS RATIO
$t_D = \frac{\eta t}{r^2}$

Use of this correlation is illustrated in Example D.17. The result may be of no greater accuracy than simply assuming $c_f = 4 \times 10^{-6}$ psi^{-1}, since only one of the many variables affecting c_f has been taken into account.

Example D.17 – Estimation of Formation Compressibility

Problem. Estimate the formation compressibility c_f for a reservoir with 20% porosity.

Solution. From Fig. D-22, $c_f = 3.6 \times 10^{-6}$ psi^{-1}.

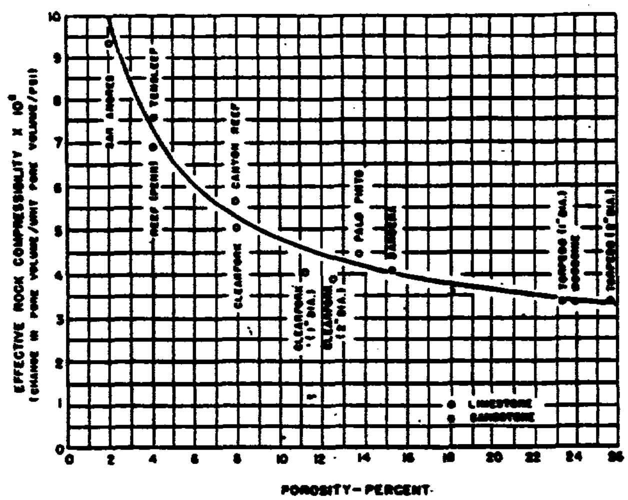

Fig. D-22 – Formation compressibility.[15]

Exercises

Results of pressure transient test analysis sometimes are combined with rock and fluid properties to calculate the following quantities:

Total reservoir flow rate,
$q_{Rt} = q_o B_o + q_w B_w + (q_g - R_s q_o/1{,}000) B_g$.
Total mobility,
$\lambda_t = k_o/\mu_o + k_w/\mu_w + k_g/\mu_g$.
Total compressibility,
$c_t = c_o S_o + c_w S_w + c_g S_g + c_f$.

The following exercises require calculation of q_{Rt}, λ_t, and c_t for two cases.

D.1. Calculate q_{Rt}, λ_t, and c_t for an undersaturated oil reservoir with the following properties.

q_o = 100 STB/D,
q_w = 20 STB/D,
q_g = $q_o R_s$ (reservoir produces dissolved gas only),
Reservoir pressure = 4,000 psia,
Reservoir temperature = 220°F,
R_s = 400 scf/STB,
γ_g = 0.7,
γ_o = 0.85,
Water salinity = 25,000 ppm (2.5% NaCl),
k_o = 20 md,
k_w = 0.93 md,
k_g = 0 (no free-gas saturation),
ϕ = 0.18,
S_o = 0.65,
S_w = 0.35, and
S_g = 0.

D.2. Calculate q_{Rt}, λ_t, and c_t for a saturated oil reservoir with the following properties:

q_o = 100 STB/D,
q_w = 5 STB/D,
q_g = 250 Mscf/D,
Oil gravity = 38°API,
Gas gravity = 0.8,
Reservoir pressure = 2,000 psia,
Reservoir temperature = 200°F,
k_o = 100 md,
k_w = 3.3 md,
k_g = 7.25 md,
Water salinity = 27,500 ppm,
S_w = 0.25,
S_g = 0.05,
S_o = 0.70, and
ϕ = 0.18.

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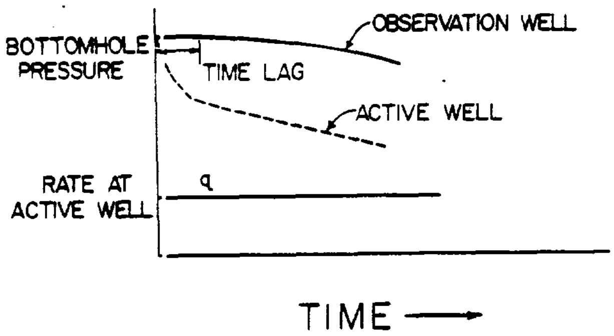


Fig. 6.1 – Pressure response in interference test.

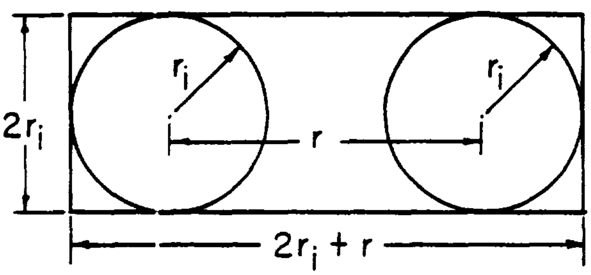


Fig. 6.2 – Region investigated in interference test.

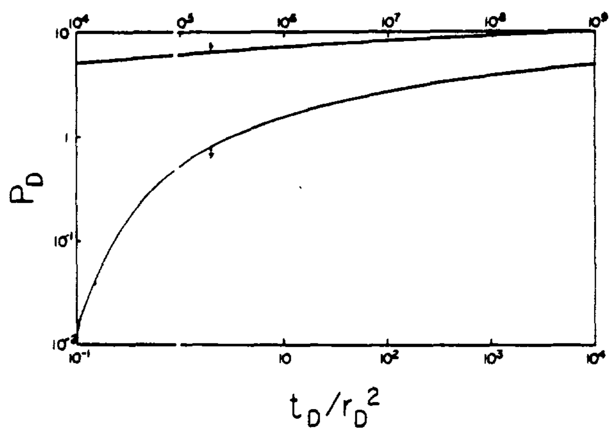


Fig. 6.3 – Exponential integral solution.

and

$$t_D = \frac{0.000264\,kt}{\phi\mu c_t r_w^2}.$$

Fig. 6.3 can be used in the following way to analyze interference tests.

1. Plot pressure drawdown in an observation well, $\Delta p = p_i - p_r$, vs. elapsed time t on the same size log-log paper as the full-scale, type-curve version of Fig. 6.3 using an undistorted curve (the reader can prepare such a curve easily).
2. Slide the plotted test data over the type curve until a match is found. (Horizontal and vertical sliding both are required.)
3. Record pressure and time match points, $(p_D)_{MP}$, Δp_{MP} and $[(t_D/r_D^2)_{MP}, t_{MP}]$.
4. Calculate permeability k in the test region from the pressure match point:

$$k = 141.2\frac{qB\mu}{h}\frac{(p_D)_{MP}}{(\Delta p)_{MP}}.$$

5. Calculate ϕc_t from the time match point:

$$\phi c_t = \left(\frac{0.000264\,k}{\mu r^2}\right)\left[\frac{t_{MP}}{(t_D/r_D^2)_{MP}}\right].$$

Example 6.1 – Interference Test in Water Sand

Problem. An interference test was run in a shallow-water sand. The active well, Well 13, produced 466 STB/D water. Pressure response in shut-in Well 14, which was 99 ft from Well 13, was measured as a function of time elapsed since the drawdown in Well 13 began. Estimated rock and fluid properties include $\mu_w = 1.0$ cp, $B_w = 1.0$ RB/STB, $h = 9$ ft, $r_w = 3$ in., and $\phi = 0.3$. Total compressibility is unknown. Pressure readings in Well 14 were as given in Table 6.1. Estimate formation permeability and total compressibility.

Solution. We assume that the aquifer is homogeneous, isotropic, and infinite-acting; we use the *Ei*-function type curves to estimate k and c_t. Data to be plotted are presented in Table 6.2. The data fit the *Ei*-function type curve well. A pair of match points are ($\Delta t = 128$ minutes, $t_D/r_D^2 = 10$) and ($\Delta p = 5.1$ psi, $p_D = 1.0$). (See Fig. 6.4.) Thus,

$$k = 141.2\frac{qB\mu}{h}\frac{(p_D)_{MP}}{(\Delta p)_{MP}}$$

$$= \frac{(141.2)(466)(1.0)(1.0)}{(9.0)}\frac{(1.0)}{(5.1)}$$

$$= 1{,}433 \text{ md},$$

and

$$c_t = \frac{0.000264}{\phi r^2}\frac{k}{\mu}\frac{(t_{MP}/60)}{(t_D/r_D^2)_{MP}}$$

I

DETERMINATION OF PORE VOLUME, ϕh

FROM PRESSURE RESPONSE TO FRAC TREATMENT

USING EI SOLUTION
(BY SUPERPOSITION)

BASIC FORMULA:

$$\Delta P = \frac{q \mu B}{141.6\, Kh} EI\left[\frac{-r^2}{4 \eta t}\right]$$

$$\eta = \frac{6.328\, K}{C_T \mu \phi}$$

q = Bbl/day
μ = vis, cP
B = FVF
K = darcys
h = feet
t = days
ϕ = porosity, fraction
C_T = vol/vol/#
r = distance between wells

RECOGNIZE TOTAL MOBILITY:

$$\lambda_T = \frac{K_o}{\mu_o} + \frac{K_g}{\mu_g} + \frac{K_w}{\mu_w} \quad \text{(John Lee, ref. 3)}$$

use symbol $\left(\frac{K_T}{\mu_T}\right)$

FROM CURVE MATCHING OF EI SOLUTION
DETERMINE $\left(\frac{K_T}{\mu_T}\right) h$ and η

DIVIDE

$$\frac{\left(\frac{K_T}{\mu_T}\right) h}{\frac{6.328}{C_T \phi}\left(\frac{K}{\mu_T}\right) h} = \frac{\left(\frac{K_T}{\mu_T}\right) h}{\eta}$$

FROM WHICH

$$\phi h = \frac{\left(\frac{K_T}{\mu_T}\right) h \times 6.328}{\eta \times C_T}$$

APPENDIX II

DETERMINATION OF Koh FROM $\left(\frac{K_T}{\mu_T}\right)h$ AND Kg/Ko

In the frac pulse testing described herein, as well as the other interference tests where a significant amount of free gas is present, the resulting transmissibility determined will be $\left(\frac{K_T}{\mu_T}\right)h$; and additional information is needed to determine Koh.

It appears that the additional information needed is the producing GOR and PVT properties of Bg, Bo, uo, and ug.

As shown on page 2 following, it appears that the ratio of $koh/\left(\frac{K_T}{\mu_T}\right)h$ can be determined from only Kg/Ko and the fluid viscosities. Since Kg/Ko can be determined from the producing GOR (along with the presumably known quantities, Bg, Bo, uo and ug), then, essentially these are the only additional data required for any reservoir. Acordingly Koh can be determined independent of any knowledge of Kg/Ko or Kro relations (John Lee, reference 1).

This unique relation for the approximate PVT properties of West Puerto Chiquito at 1400# reservoir pressure is shown on the graph, page 4, from data calculated on page 3.

DETERMINATION of $K_o h$ from $\left(\frac{K_T}{\mu_T}\right)h$ and K_g/K_o

Since, by definition:

$$\left.\begin{array}{l} K_{ro} \times K = K_o \\ \quad\text{and} \\ K_{rg} \times K = K_g \end{array}\right\} \text{ then } \frac{K_g}{K_o} = \frac{K_{rg} K}{K_{ro} K}$$

$$\text{and } K_g = \left(\frac{K_{rg}}{K_{ro}}\right)(K_o) = \left(\frac{K_g}{K_o}\right)K_o$$

So that, given K_g/K_o & K_{ro}, K_{rg} is defined

TOTAL MOBILITY $\lambda_T = \frac{K_o}{\mu_o} + \frac{K_g}{\mu_g}$ (John Lee ref 3)

use symbol $\frac{K_T}{\mu_T}$

$$\text{So } \frac{K_T}{\mu_T} = \frac{K_o}{\mu_o} + \frac{K_g}{\mu_g} = \frac{K_{ro} K}{\mu_o} + \frac{K_{rg} K}{\mu_g}$$

$$\text{and } \left(\frac{K_T}{\mu_T}\right)h = \left(\frac{K_{ro}}{\mu_o} + \frac{K_{rg}}{\mu_g}\right)Kh$$

$$Kh = \frac{\left(\frac{K_T}{\mu_T}\right)h}{\left(\frac{K_{ro}}{\mu_o} + \frac{K_{rg}}{\mu_g}\right)}$$

$$\text{and ratio } K_o h \Big/ \left(\frac{K_T}{\mu_T}\right)h = Kh \times K_{ro} = \frac{K_{ro}}{\left(\frac{K_{ro}}{\mu_o} + \frac{K_{rg}}{\mu_g}\right)}$$

$$\text{\& finally, ratio} = \frac{1}{\left(\frac{1}{\mu_o} + \frac{K_g}{K_o \mu_g}\right)}$$

DETERMINATION of $K_o h$ from $\left(\frac{K_T}{\mu_T}\right) h$

For Reservoir press = 1400#

$K_o h$ = darcy feet

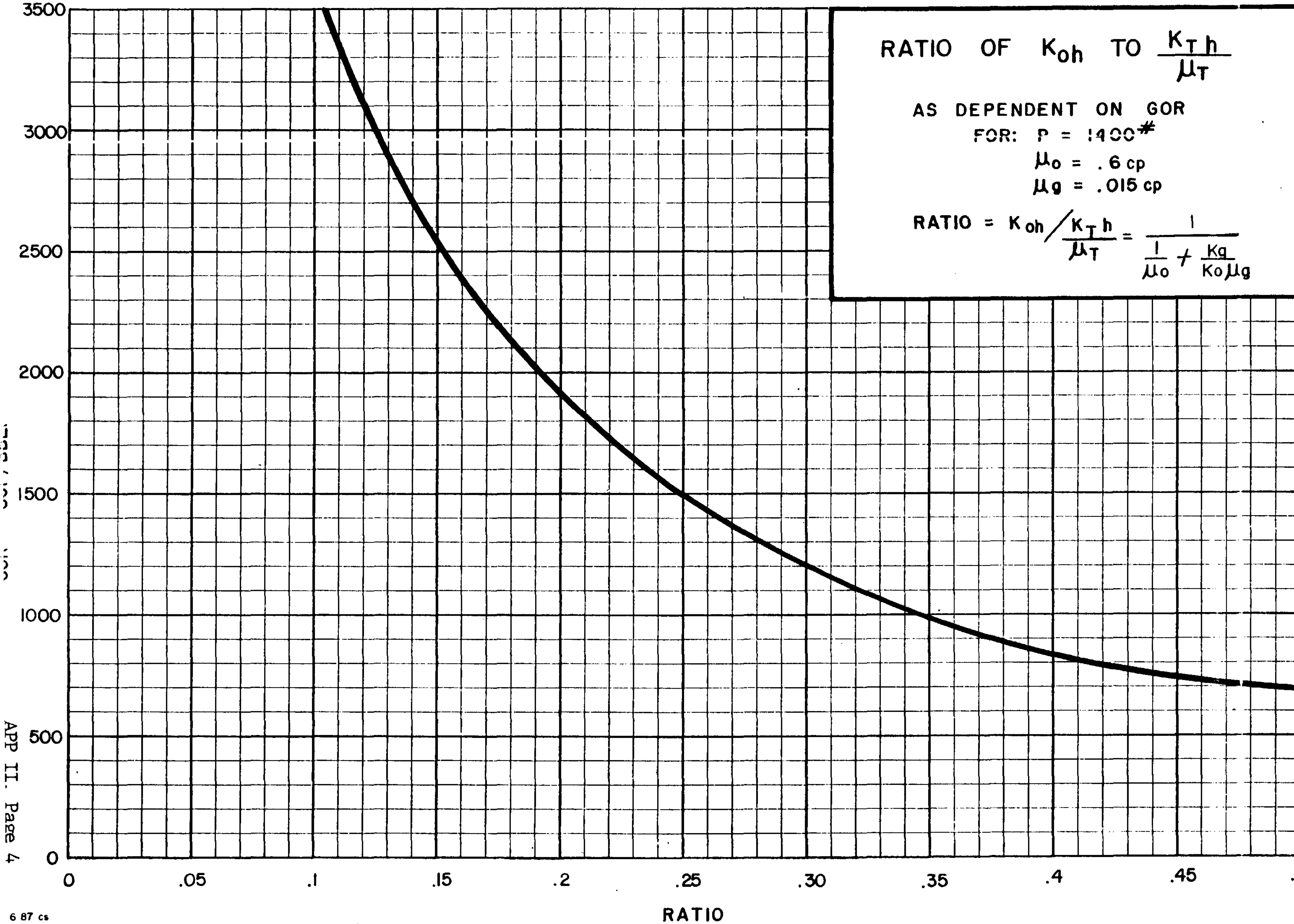
$$\left(\frac{K_T}{\mu_T}\right) = \lambda_T = \frac{K_o}{\mu_o} + \frac{K_g}{\mu_g}$$

Use: $\mu_o = .6$ $B_o = 1.28$ $B_g = 525$ scf/res bbl

$R_s = 500$ cf/bbl $\mu_g = .015$ cp

R GOR (SCF/BBL)	K_g/K_o	RATIO $K_o h / \frac{K_T h}{\mu_T} = \frac{1}{\left(\frac{1}{\mu_o} + \frac{K_g}{K_o \mu_g}\right)}$
(1)	(2)	(3)
750	.0093	.437
1000	.0186	.344
1500	.0372	.241
2000	.0558	.186
2500	.0744	.151
3500	.1116	.110

(2) $K_g/K_o = \frac{(R - R_s)}{B_o B_g} \cancel{\times \frac{\mu_g}{\mu_o}}$



RATIO OF K_{oh} TO $\frac{K_T h}{\mu_T}$
AS DEPENDENT ON GOR
FOR: P = 1400#
μ_o = .6 cp
μ_g = .015 cp
RATIO = $K_{oh} / \frac{K_T h}{\mu_T} = \frac{1}{\frac{1}{\mu_o} + \frac{K_g}{K_o \mu_g}}$
3500
3000
2500
2000
1500
1000
500
0
0
.05
.1
.15
.2
.25
.30
.35
.4
.45
.5
RATIO

6 87 cs