DOE-METC GAS WELL TESTING SERVICE

CONTRACT NO. DE-AC21-78MC08096

WELL TEST ANALYSIS FOR COMBUSTION ENGINEERING WELL NO. 1

VOLUME I

Submitted to
U.S. Department of Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

by

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FOR

COMBUSTION ENGINEERING WELL NO. 1

INTRODUCTION

The Combustion Engineering Power Systems Group Well No. 1, located near the town of Belle Vernon in Allegheny County, Pennsylvania, was drilled to a total depth of about 7,500 feet and completed through perforations at 7,020 to 7,080 feet and 7,330 to 7,440 feet in the Burkett and Marcellus shales, respectively. The well was fractured through the two perforated intervals separately by Halliburton using Versagel with CO_2. The upper zone was propped with 37,000 pounds of 20- to 40-mesh sand and 37,000 pounds of 80- to 100-mesh sand. The lower zone employed 880,000 pounds of 20- to 40-mesh sand and 880,000 pounds of 80- to 100-mesh sand. A schematic diagram of the well is shown in Figure 1.

OPERATIONS

Reservoir Data, Inc. arrived at the well site on September 29. The surface equipment shown in Figure 2 was installed on September 30 but the compressor malfunctioned and operations were temporarily suspended. The compressor was replaced with a cylinder of compressed nitrogen on October 1, but an attempt to reach bottom with several sinker bars failed when a restriction was encountered at 1840 feet. A decision was made to abandon the test if the next well in the program was ready for testing; otherwise, the test would be conducted recording surface pressures. In the meantime, operational problems were experienced in setting the back pressure regulator and time was lost until the problem was rectified. Since the next well was not ready, the well was opened for testing at 11 a.m. on October 4.

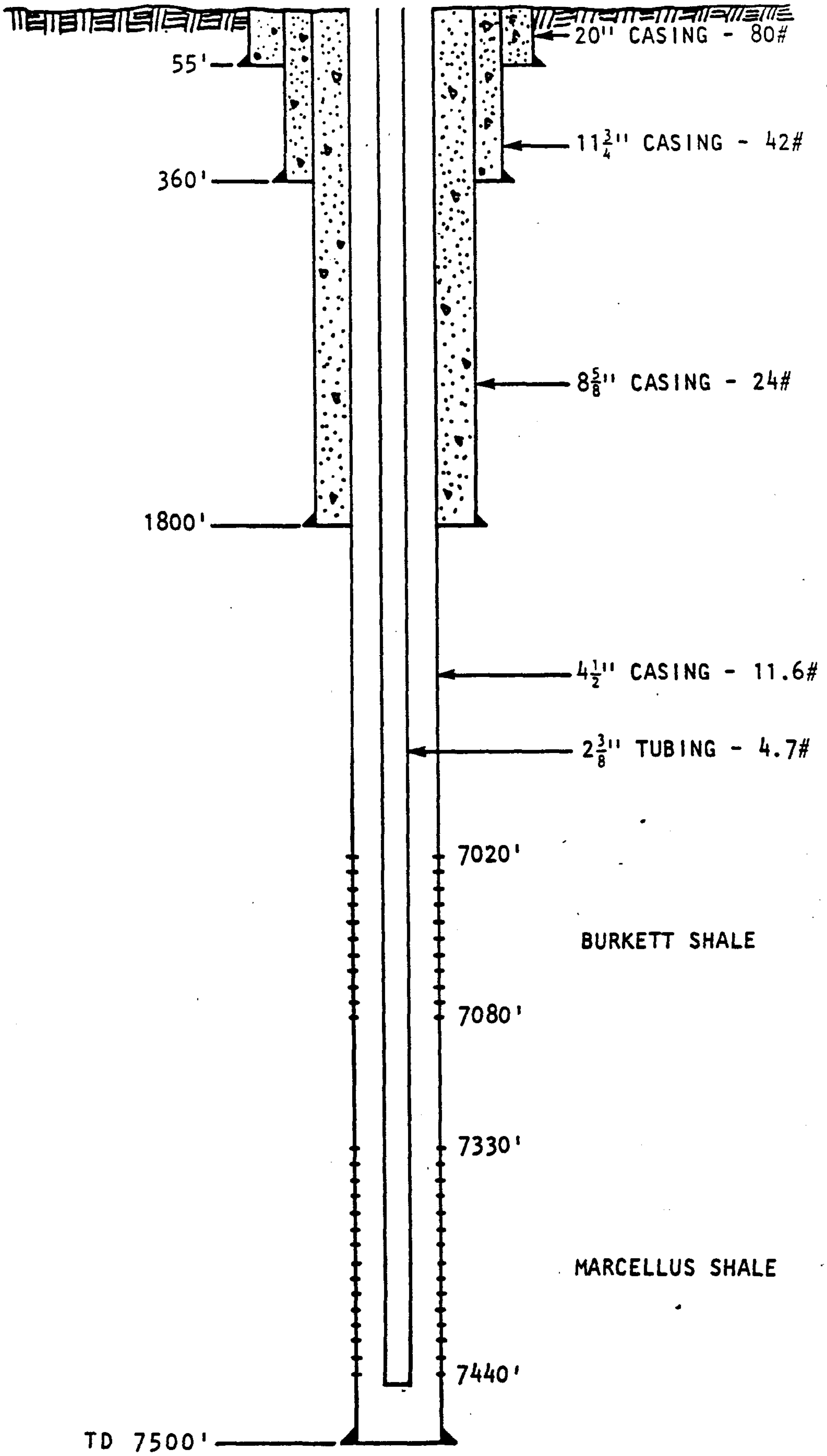

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FIGURE 1

WELL SCHEMATIC OF C.E. POWER SYSTEMS GROUP WELL NO. 1

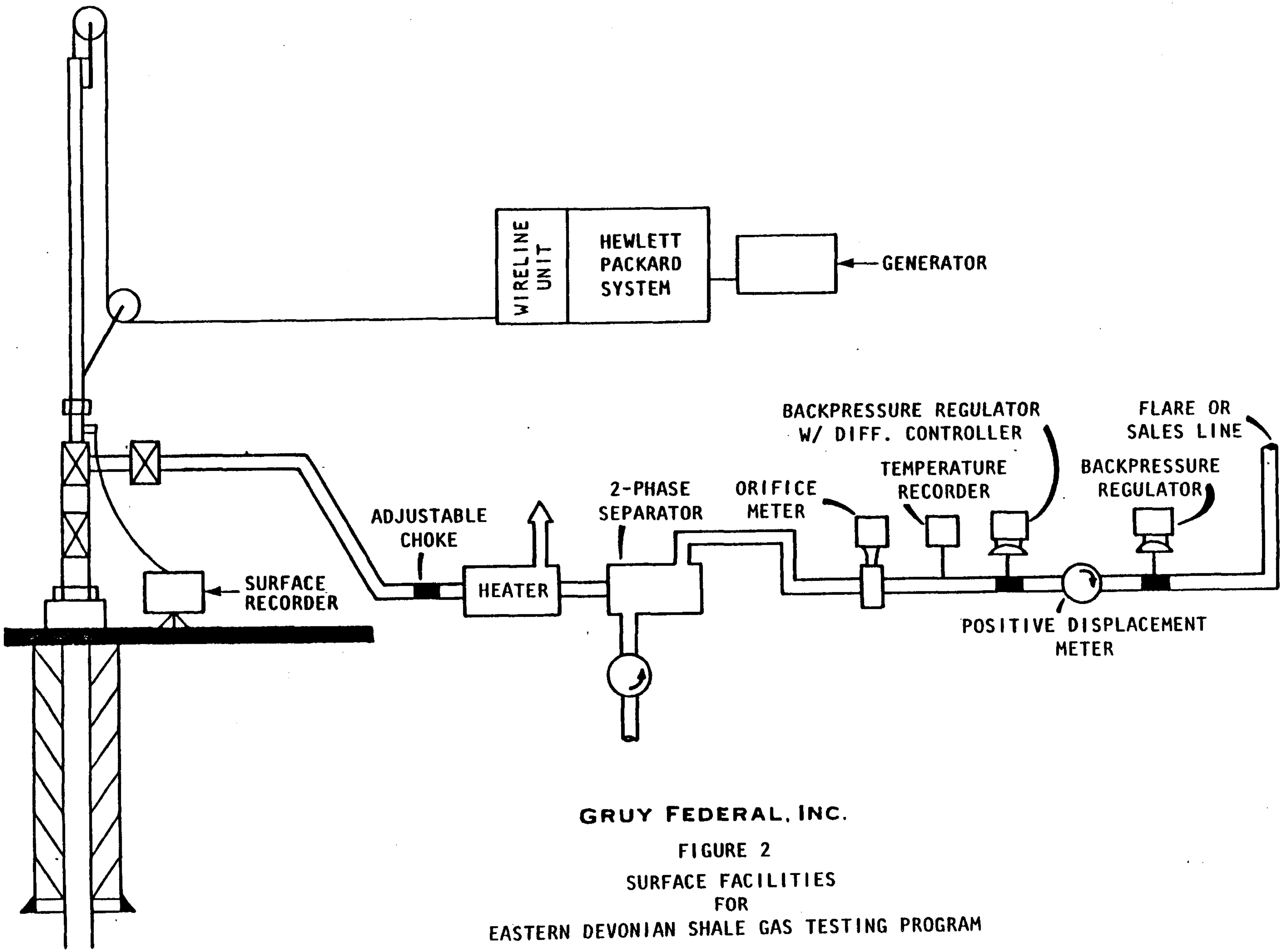

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FIGURE 2

SURFACE FACILITIES
FOR
EASTERN DEVONIAN SHALE GAS TESTING PROGRAM

On October 6 the generator failed, making it impossible to record with the Hewlett-Packard gauge, and surface pressures were recorded on a backup Amerada RPG-6 gauge for the remaining test period. The well was shut in at 1 p.m. on October 8 to monitor a buildup; it was reopened on October 12 at 3 p.m.

A complete production rate history during the test period is shown in Figure 3. Despite the best efforts, rates could not be held constant. The test was concluded at 9 a.m. on October 15, 1979. The data for the last 12 hours were of poor quality and were not used, because flow rates could not be calculated accurately.

FLOW REGIMES

According to transient pressure theory, if a gas well produces at a constant rate into an infinite capacity fracture, a plot of log m(p) against the log of time should show three patterns: an early straight-line portion with a slope of 1, a second straight-line portion with a slope of 0.5, and a line convex during the late stages of flow. These patterns correspond to (1) wellbore storage effects, (2) linear flow into an infinite capacity fracture, and (3) radial or quasi-radial flow toward the fracture. From material balance considerations, however, for a well not producing at a constant rate, a plot of log m(p) should exhibit similar characteristics when plotted against log $\sum q_n t_n$. Figure 4 shows such a plot for the first drawdown. Wellbore storage effects can be seen to last for $\sum q_n t_n$ approximately equal to 1200, which corresponds to t = 7 hours, followed by linear flow. Figure 5 depicts much longer storage effects (about 50 hours) during the buildup. Figure 6 shows very little storage effect for the second drawdown.

ESTIMATION OF FRACTURE LENGTH FROM FRAC DATA

The upper zone was fractured using 74,000 pounds of sand. Assuming a 10 percent flowback of sand, a grain density of 2.66 grams per cubic centi-

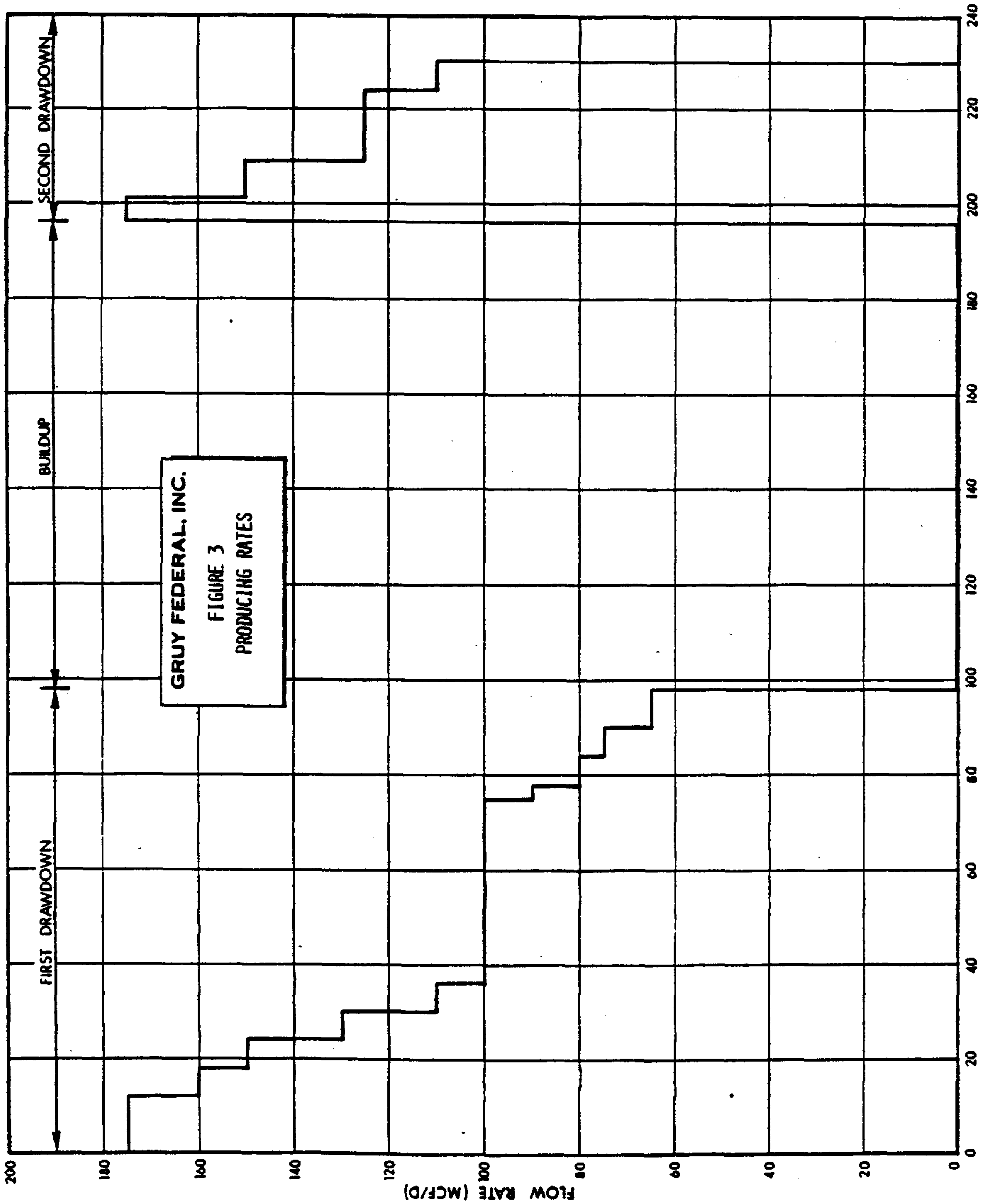

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FIGURE 3
PRODUCING RATES
FIRST DRAWDOWN
BUILDUP
SECOND DRAWDOWN
FLOW RATE (MCF/D)
TIME (HOURS)
0
20
40
60
80
100
120
140
160
180
200
220
240

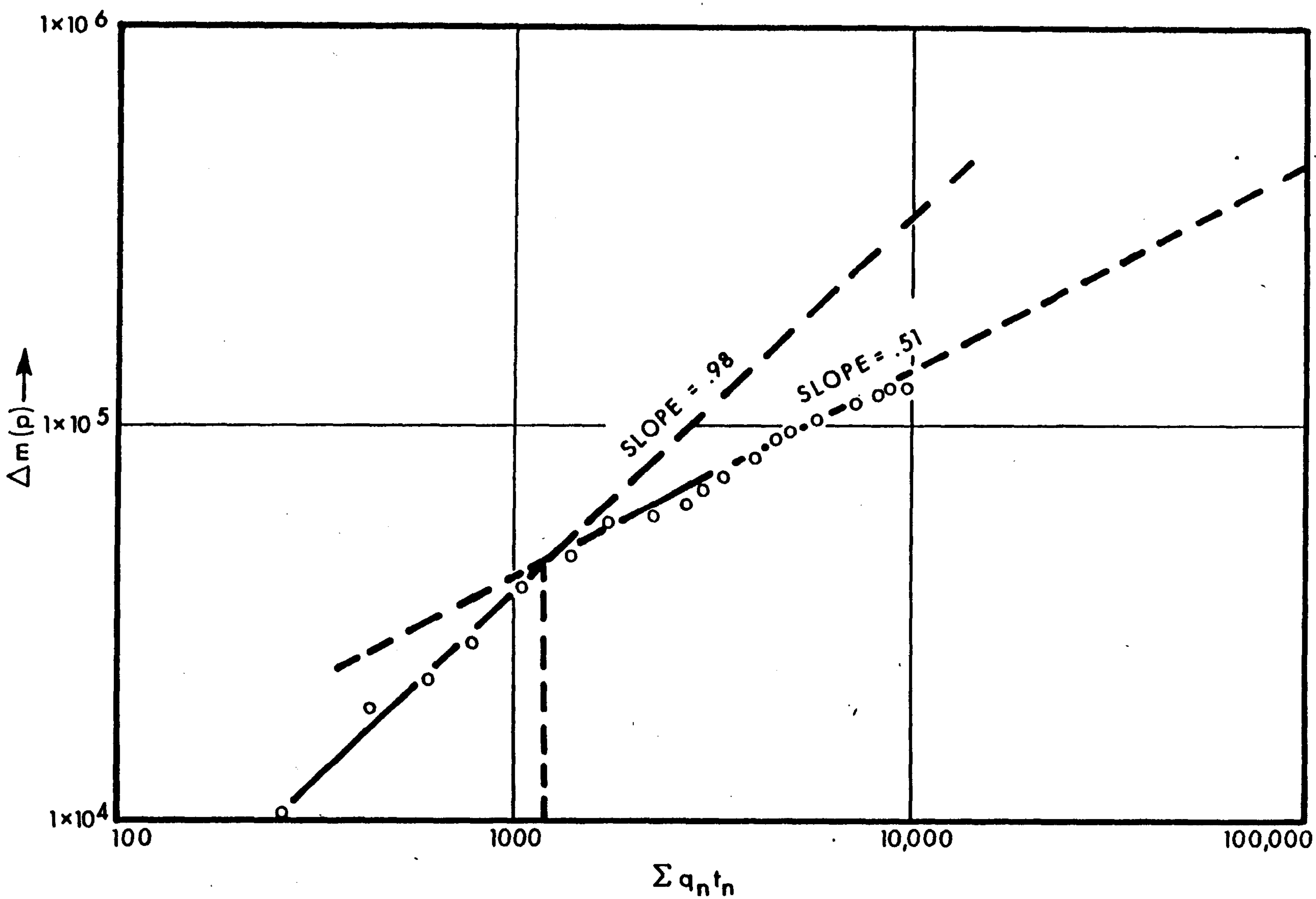

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FIGURE 4
FIRST DRAWDOWN
LOG $\Delta m(p)$ VS LOG $\Sigma q_n t_n$

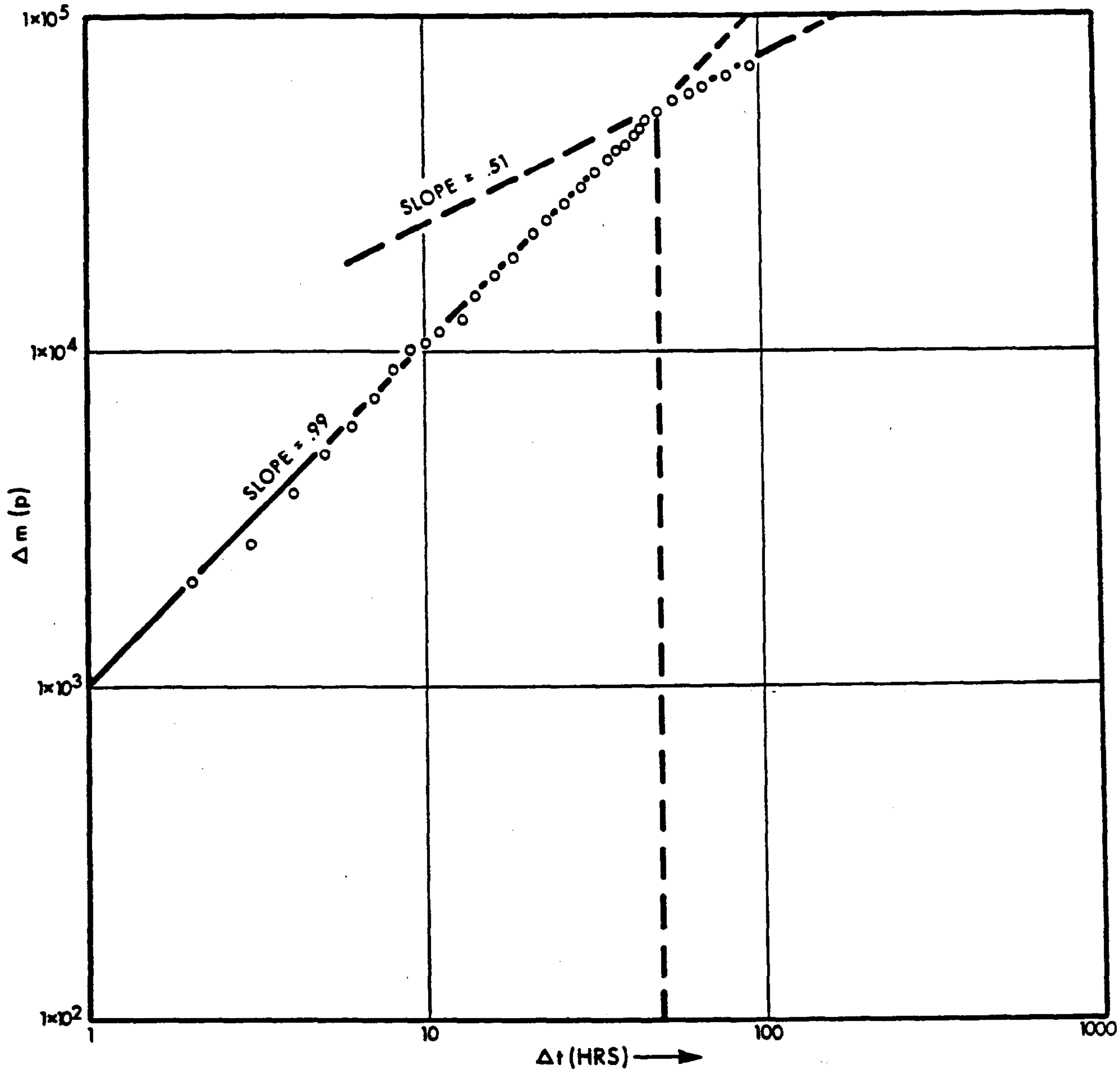

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FIGURE 5
BUILDUP
LOG $\Delta m(p)$ VS LOG Δt(HRS)

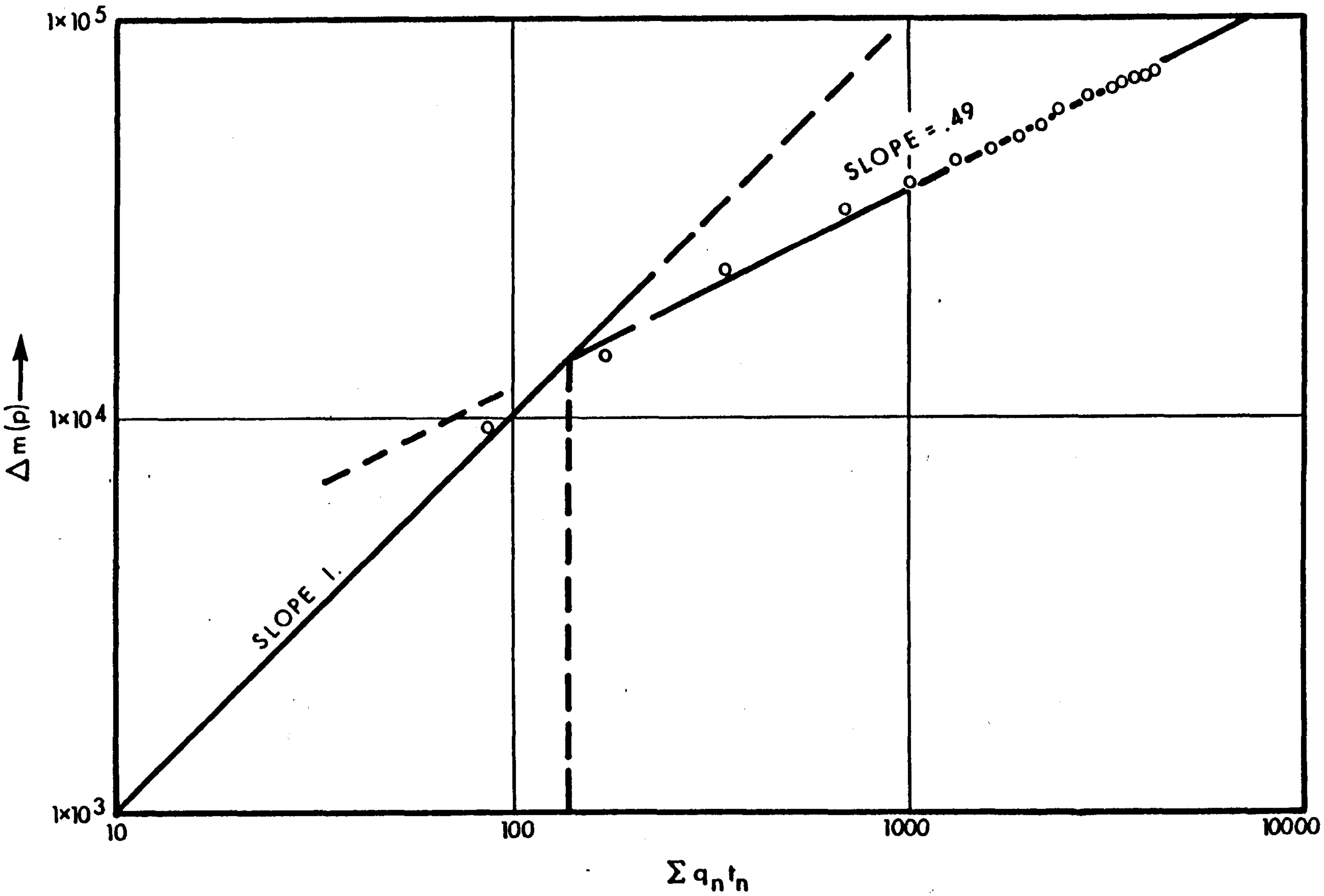

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FIGURE 6

SECOND DRAWDOWN

LOG $\Delta m(p)$ VS LOG $\Sigma q_n t_n$

meter, and a fracture porosity of 33 percent, the fracture volume was estimated to be 598.87 cubic feet. By further assuming that the fracturing had created a fracture 60 feet high (through perforations at 7,020 to 7,080 feet) and 0.1 to 0.2 inches wide, the fracture half-length was estimated to lie between 299 to 599 feet. This assumes that 90 percent of the sand created a fracture within the zone of interest; effective fracture volume contributing to flow would actually be determined by the amount of sand remaining in the zone of interest. Similar calculation gives fracture half length estimates ranging from 388 to 777 feet for the lower zone.

As discussed later, actual volume of the fracture contributing to flow of gas in this well was extremely small.

ESTIMATION OF MATRIX PERMEABILITY

Independent estimates of reservoir permeabilities can be made by analyzing the pressure data. On the basis of transient flow theory, for radial flow a buildup plot of m(p)[1,2] versus superimposed time-rate should give a straight line with a slope inversely proportional to formation permeability. For a drawdown with variable flow rates, $m(p_n)/q_n$ plotted against superimposed time rate X_n/q_n should yield a similar curve. However, for a tight gas well with vertical fractures, radial flow may not occur during tests of such short duration. Hence the slopes of these curves are indicative not of the matrix permeability, but rather of the integrated average permeability of the formation and the fracture. The longer the test time, the nearer the calculated (apparent) permeability approaches the matrix permeability.

Surface pressures were converted to bottomhole pressures using the Cullender and Smith method. Gas properties were obtained from empirical correlations.

The slopes calculated from Figures 7, 8 and 9 are those which give apparent flow capacities ($K_a h$) of 0.131, 0.139 and 0.282 respectively. The value of the apparent matrix permeability K_a would depend on the net productive interval h.

An extensive log analysis was performed and the following four cases, each based on a different reservoir geometry, were considered for analyses of the test results.

Case I. This is the simplest case and would give the most conservative values for matrix permeability and fracture half lengths. In this case the net productive interval was taken to be 60 feet for the upper zone and 110 feet for the lower zone.

Case II. Log analysis shows that the Burkett is the better gas-producing interval; this was confirmed by information available from the operators. In the opinion of CE, estimated production from the Burkett was 3 to 4 times that from the Marcellus.

The log analysis also shows a water-bearing zone within the lower perforations, which may result in a water column in the wellbore causing a back-pressure on the lower zone and thus preventing even minimal gas production from the lower zone. Therefore, in this case the lower zone was ignored and only the net productive interval of 60 feet for the upper zone was taken into account.

Case III. Analysis of the available logs indicates that neither the entire upper zone nor the entire lower zone could be productive of gas. It is hard to quantify the net total intervals productive of gas in these zones. Using an arbitrary resistivity cutoff of 100 ohm-meters, the estimated productive intervals are 20 feet and 10 feet in the upper and lower zones respectively.

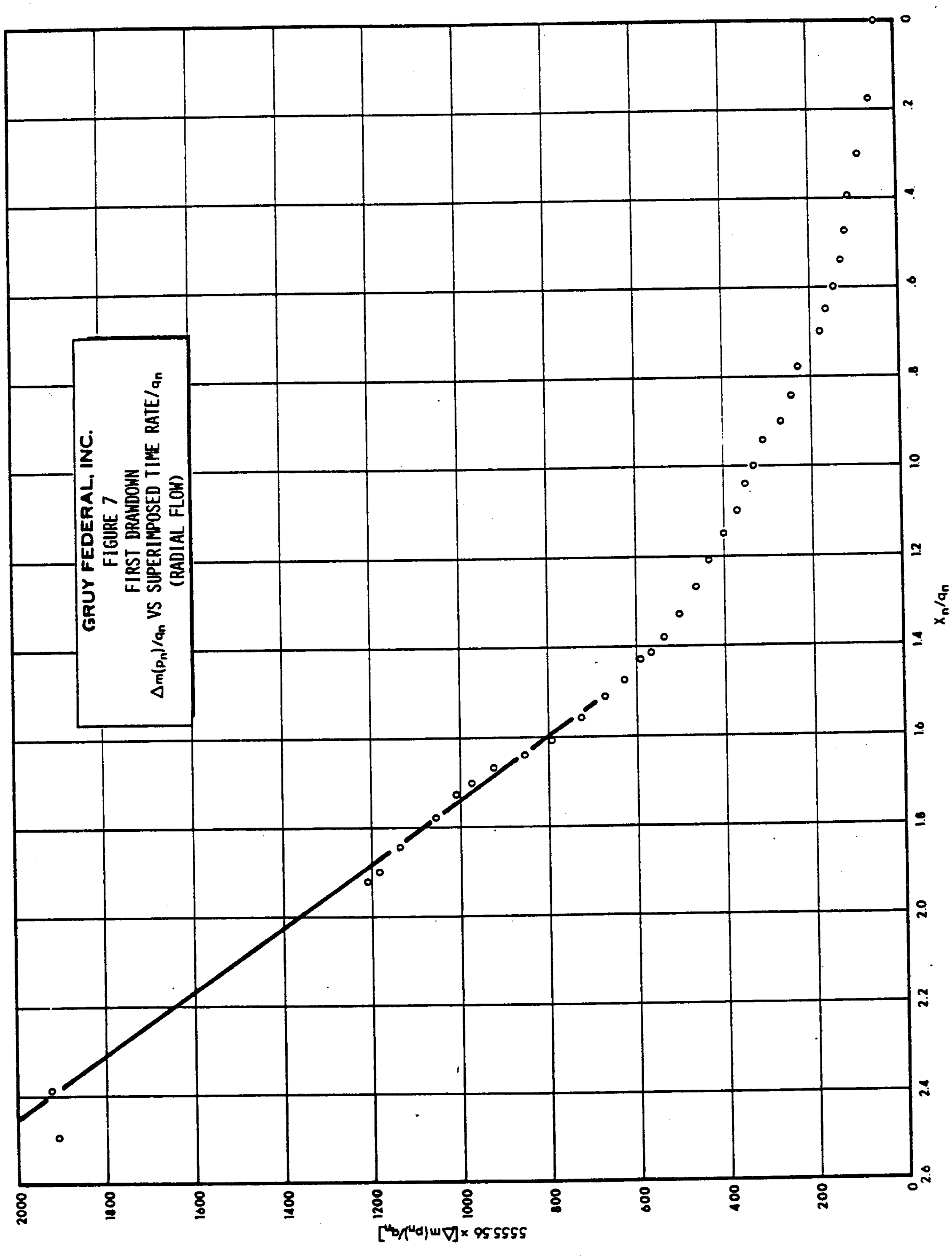
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FIGURE 7
FIRST DRAWDOWN
Δm(p_n)/q_n VS SUPERIMPOSED TIME RATE/q_n
(RADIAL FLOW)
X_n/q_n
5555.56 × [Δm(p_n)/q_n]
0
.2
.4
.6
.8
1.0
1.2
1.4
1.6
1.8
2.0
2.2
2.4
2.6
2000
1800
1600
1400
1200
1000
800
600
400
200
0

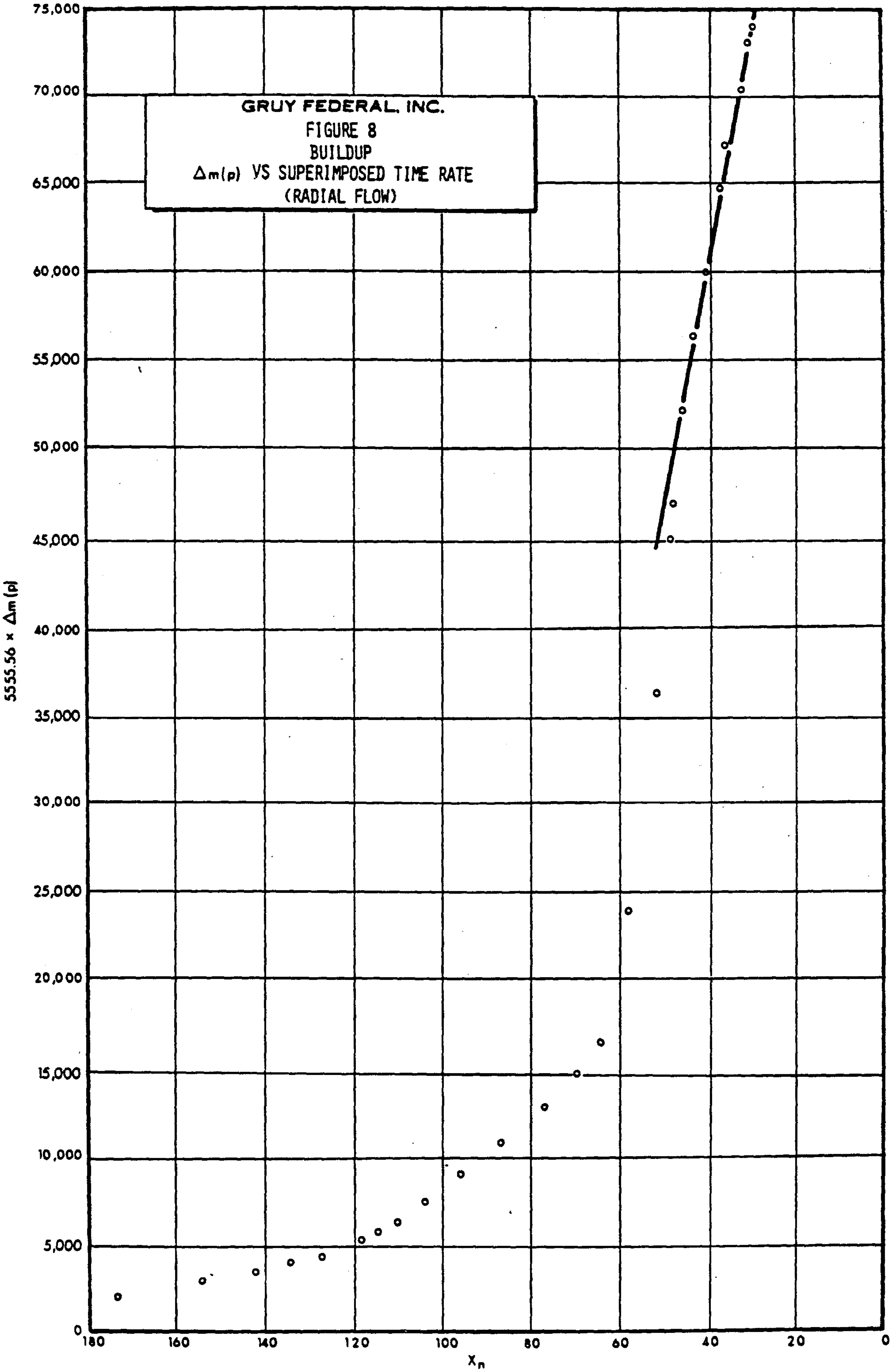

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FIGURE 8
BUILDUP
Δm(p) VS SUPERIMPOSED TIME RATE
(RADIAL FLOW)
5555.56 × Δm(p)
75,000
70,000
65,000
60,000
55,000
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
180
160
140
120
100
80
60
40
20
0
Xn

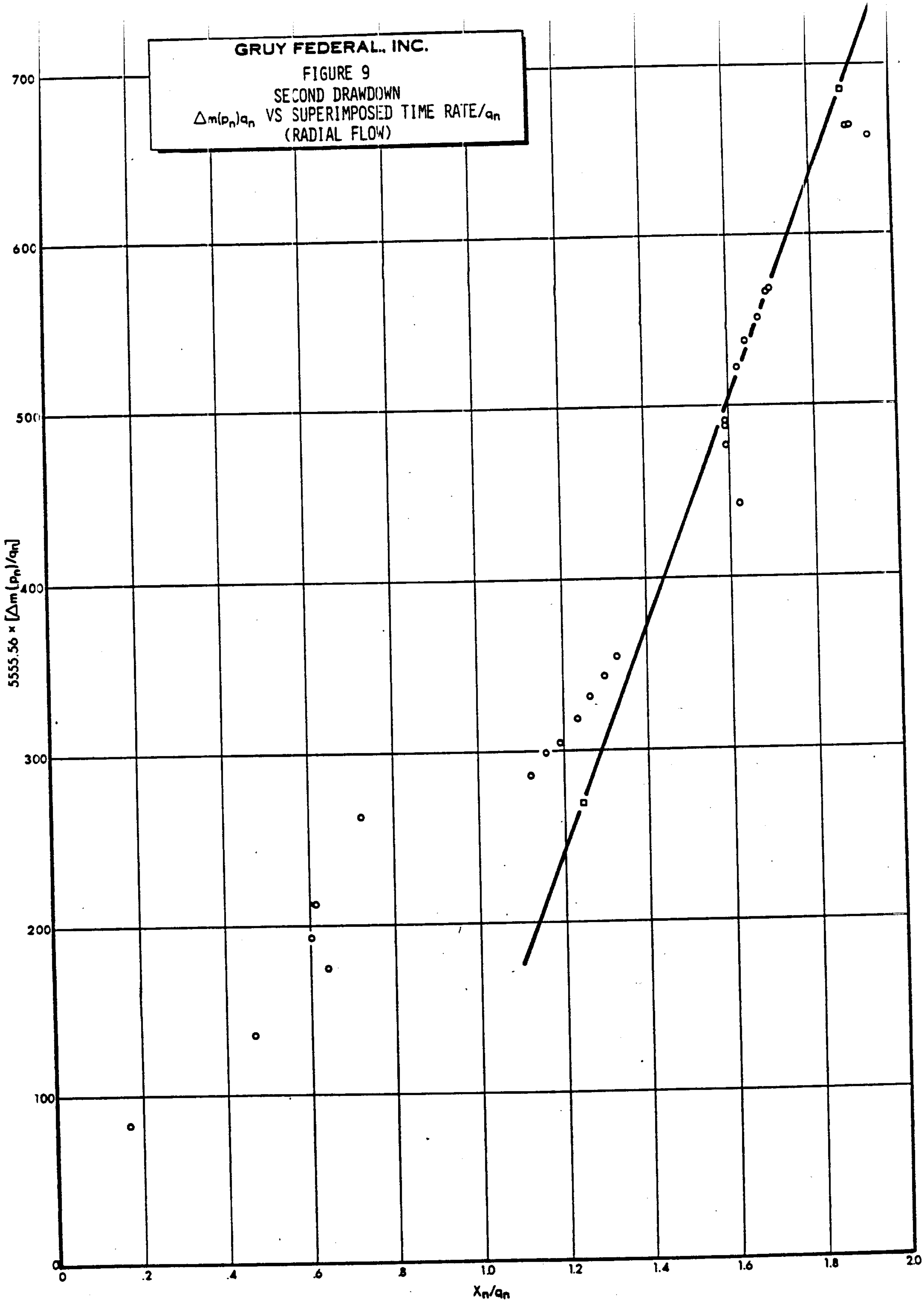
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FIGURE 9
SECOND DRAWDOWN
$\Delta m(p_n)q_n$ VS SUPERIMPOSED TIME RATE/q_n
(RADIAL FLOW)
700
600
500
400
300
200
100
0
$5555.56 \times [\Delta m(p_n)/q_n]$
0
.2
.4
.6
.8
1.0
1.2
1.4
1.6
1.8
2.0
X_n/q_n

Case IV. Extending the logic of Case II, another reservoir geometry was considered, which ignores the lower zone and considers only 20 feet of the upper zone as productive. It should be noted that this would give the most optimistic results for matrix permeability and fracture half-length.

In our opinion, these four cases cover the complete range of possible reservoir configurations in the subject well. Case I and IV are extreme cases, whereas Cases II and III would give intermediate results.

Table 1 shows the calculated apparent matrix permeabilities values for the different cases. As mentioned earlier, all these values are higher than the true matrix permeability.

Estimation of Fracture Half-Lengths Using Bottomhole Pressure Data

On the basis of transient flow theory the two drawdowns and the buildup can be analyzed to estimate fracture half-length by constructing plots similar to Figures 7, 8 and 9, the only difference being that the superimposed time-rate X_n used in these plots is for linear flow. The slopes (m') of these plots (Figures 10, 11, 12) during the period of linear flow are related to fracture and formation properties as follows:

$$m' = \frac{40.85 T_f}{X_f h_f} \sqrt{\frac{1}{k_g \mu_g \phi_g c_t}}$$

Obviously, the fracture half-length (X_f) calculated would depend on the values of K_g and h_f used, which are different for the four cases mentioned earlier.

TABLE 1

ESTIMATION OF MATRIX PERMEABILITY FROM CONVENTIONAL ANALYSES

	Permeability, millidarcies			
	CASE I	CASE II	CASE III	CASE IV
First drawdown	0.00077	0.00218	0.00437	0.00655
Buildup	0.00082	0.00232	0.00463	0.00695
Second drawdown	0.00166	0.0047	0.0094	0.0141
Arithmetic mean	0.00108	0.00307	0.00613	0.0092

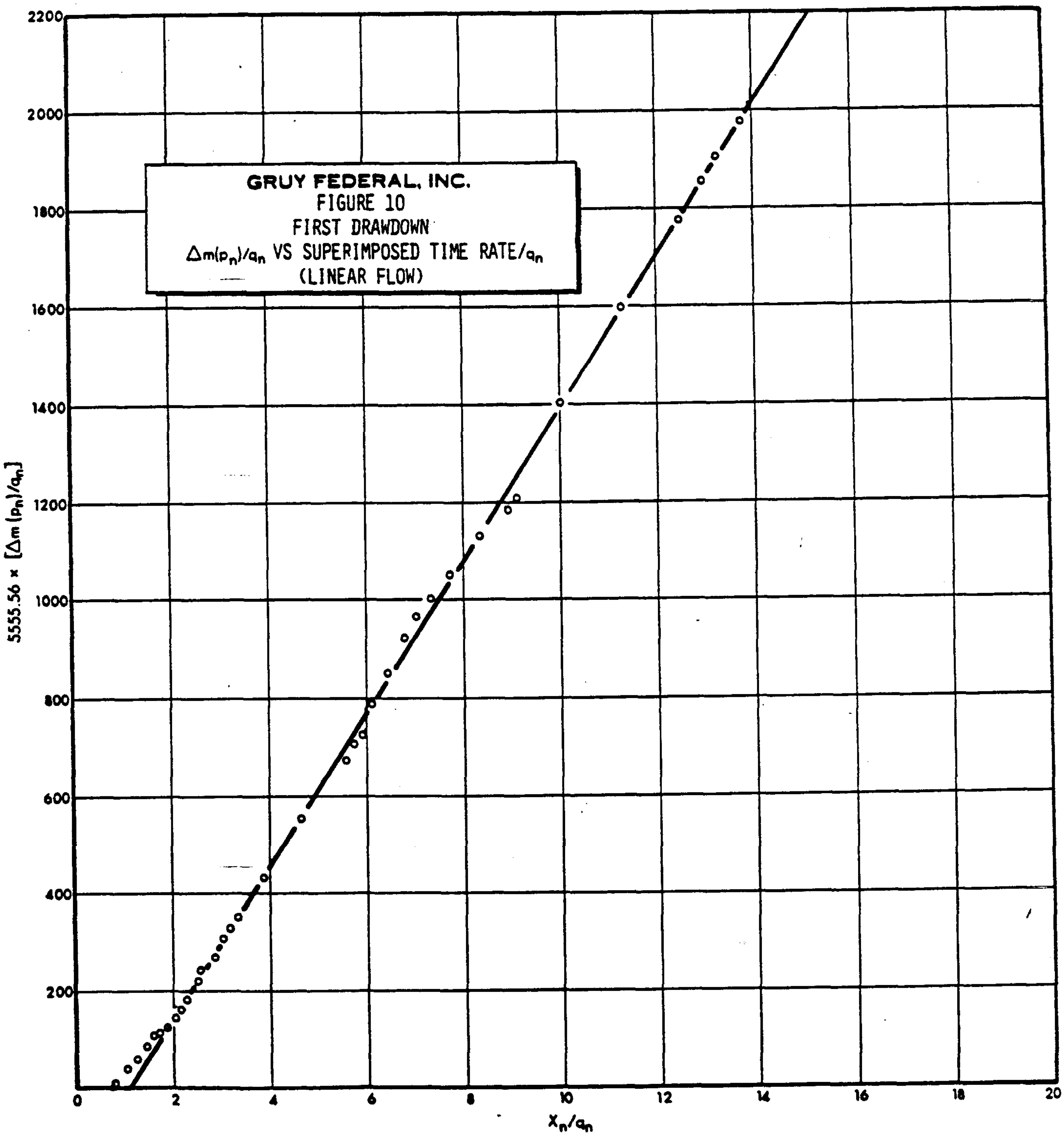

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FIGURE 10
FIRST DRAWDOWN
$\Delta m(p_n)/q_n$ VS SUPERIMPOSED TIME RATE/q_n
(LINEAR FLOW)
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
$5555.56 \times [\Delta m(p_n)/q_n]$
0
2
4
6
8
10
12
14
16
18
20
X_n/q_n

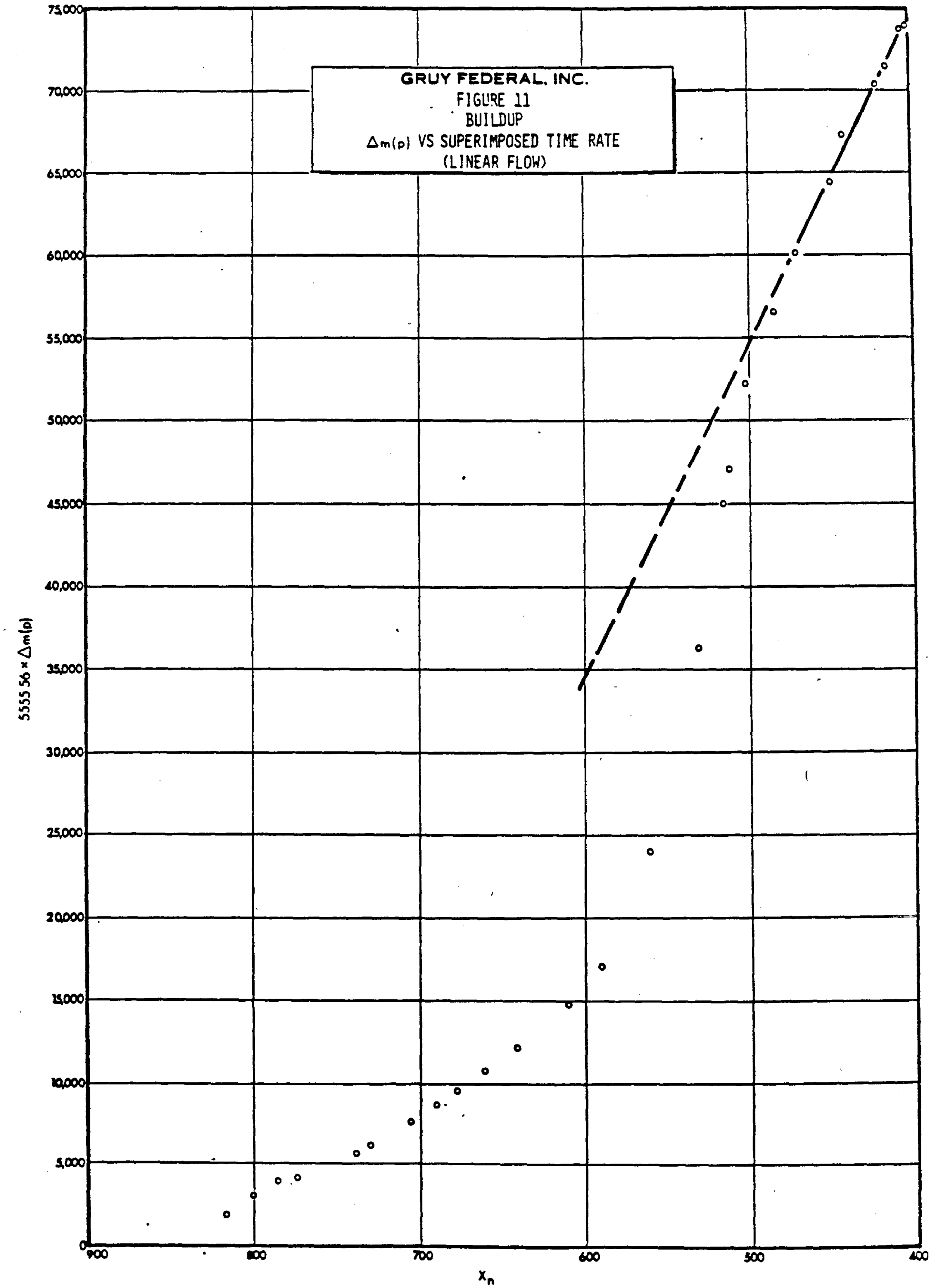
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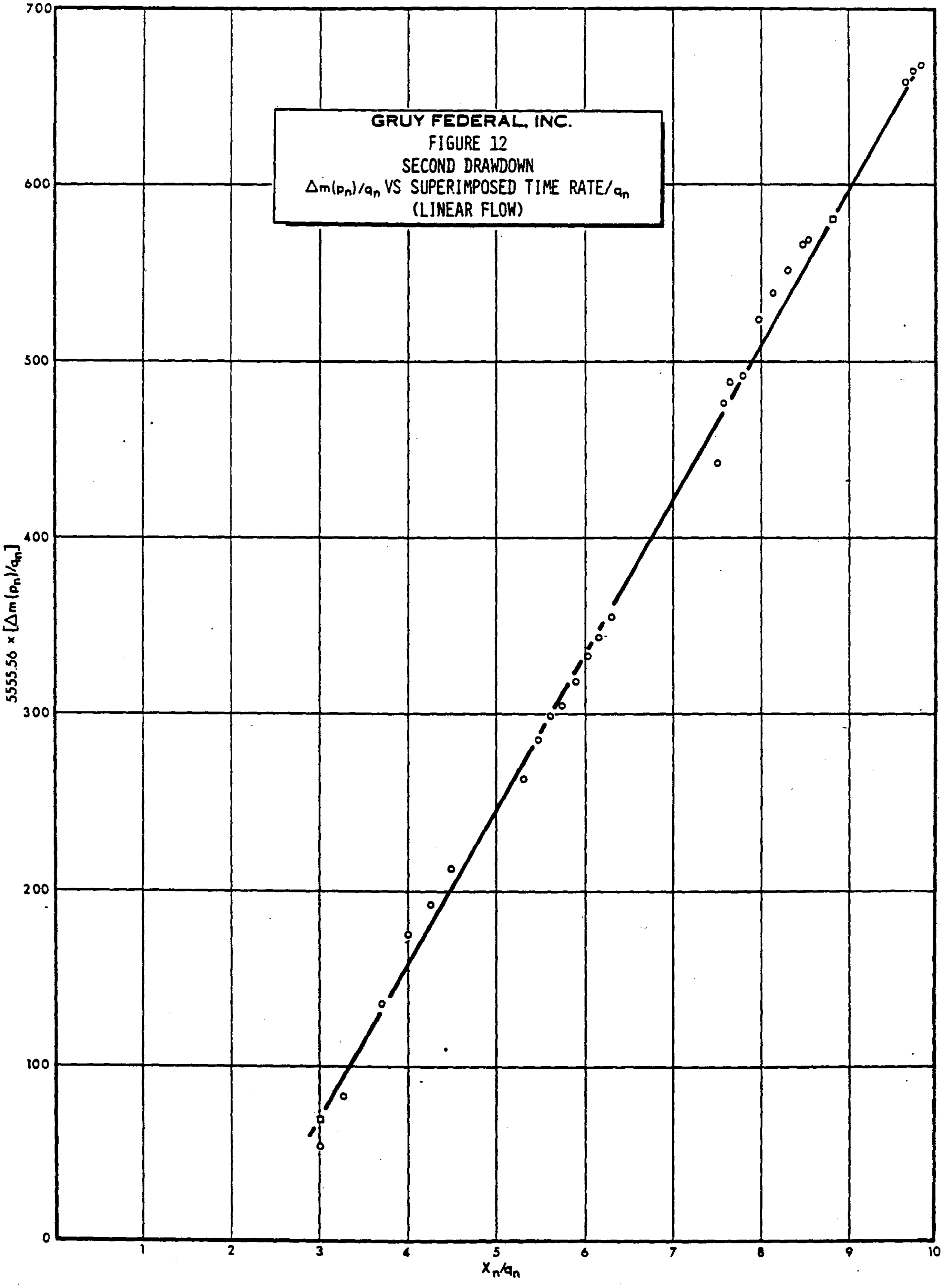
FIGURE 11
BUILDUP
Δm(p) VS SUPERIMPOSED TIME RATE
(LINEAR FLOW)
75,000
70,000
65,000
60,000
55,000
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
5555.56 × Δm(p)
900
800
700
600
500
400
Xn


GRUY FEDERAL, INC.
FIGURE 12
SECOND DRAWDOWN
$\Delta m(p_n)/q_n$ VS SUPERIMPOSED TIME RATE/q_n
(LINEAR FLOW)
700
600
500
400
300
200
100
0
1
2
3
4
5
6
7
8
9
10
$5555.56 \times [\Delta m(p_n)/q_n]$
X_n/q_n

Assuming:

ϕg = 1% (based on past experience)

T_f = 620°R (from temperature log)

μ_g = 0.0149 (first drawdown)

= 0.0158 (buildup)

= 0.0137 (second drawdown)

C_t = 0.0005931 (first drawdown)

= 0.0004983 (buildup)

= 0.000824 (second drawdown)

Table 2 shows fracture half-lengths calculated for the different cases. For Case I and Case III, it was assumed that the two created fractures are equal in length; this is not necessarily true, but it is a reasonable assumption and makes it possible to arrive at an order of magnitude for the fracture half-lengths. Average fracture half-lengths calculated lie in the range of 23 to 63 feet.

It must be pointed out, however, that this analysis assumes the flow capacities of the fractures to be infinite, which tends to give conservative results for finite capacity fractures. Using optimistic values of Kg will also tend to give conservative half-lengths. Also, since the second drawdown was of shorter duration, the results obtained are not as reliable but they have been taken into account to arrive at starting values for reservoir simulation.

History Match Using Reservoir Simulator

Gruy Federal's program library includes a three-dimensional single-phase simulator that solves the flow equations in terms of real gas pseudopotential. The model also includes wellbore storage, skin effect, finite-capacity fractures, and turbulence.

TABLE 2

ESTIMATION OF FRACTURE HALF-LENGTHS
FROM CONVENTIONAL ANALYSES*

	Fracture Half-Lengths, feet			
	CASE I	CASE II	CASE III	CASE IV
First Drawdown	23	30	51	56
Buildup	16	24	42	46
Second drawdown	30	46	80	88
Arithmetic mean	23	33	58	63

*Assuming two equal fractures in Cases I and III and using arithmetic mean permeability values for respective cases.

As mentioned earlier, matrix permeability estimates from conventional techniques are generally optimistic, whereas fracture half-length calculations are generally conservative. Therefore, the scheme adopted to obtain a history match was to reduce the matrix permeability and increase the fracture half-length. However, the effective porosity of the shale to gas was not determinable from the pressure tests. An effective porosity of 1 percent based on past experience, was chosen as the starting value for the simulator and was then adjusted until a history match was obtained. The fracture height was arbitrarily set as the height of the productive interval because no data were available to estimate it. The best match of the measured data (obtained from Case IV) is shown in Figure 13 and the reservoir parameters used to achieve this match are shown in Table 3.

No matches could be obtained for Cases I, II, and III. On the basis of the work with the reservoir simulator, it was discovered that these cases might give satisfactory matches of the measured data when one or both of two conditions were met:

(1) the fracture half-lengths were reduced below estimated half-lengths from conventional techniques for respective cases,

(2) the matrix permeability approached or exceeded values calculated by conventional techniques.

These conditions are inconsistent with pressure transient theory and thus these cases could not be representative of actual reservoir geometries.

A radioactive tracer log indicated that bulk of the sand was confined within the perforated interval of the lower zone; hence fracture half-lengths of about 26 feet calculated by conventional techniques for Case I would be unrealistic. No tracer log was available for the upper zone but other logs indicate that an extensive natural fracture system exists within and above

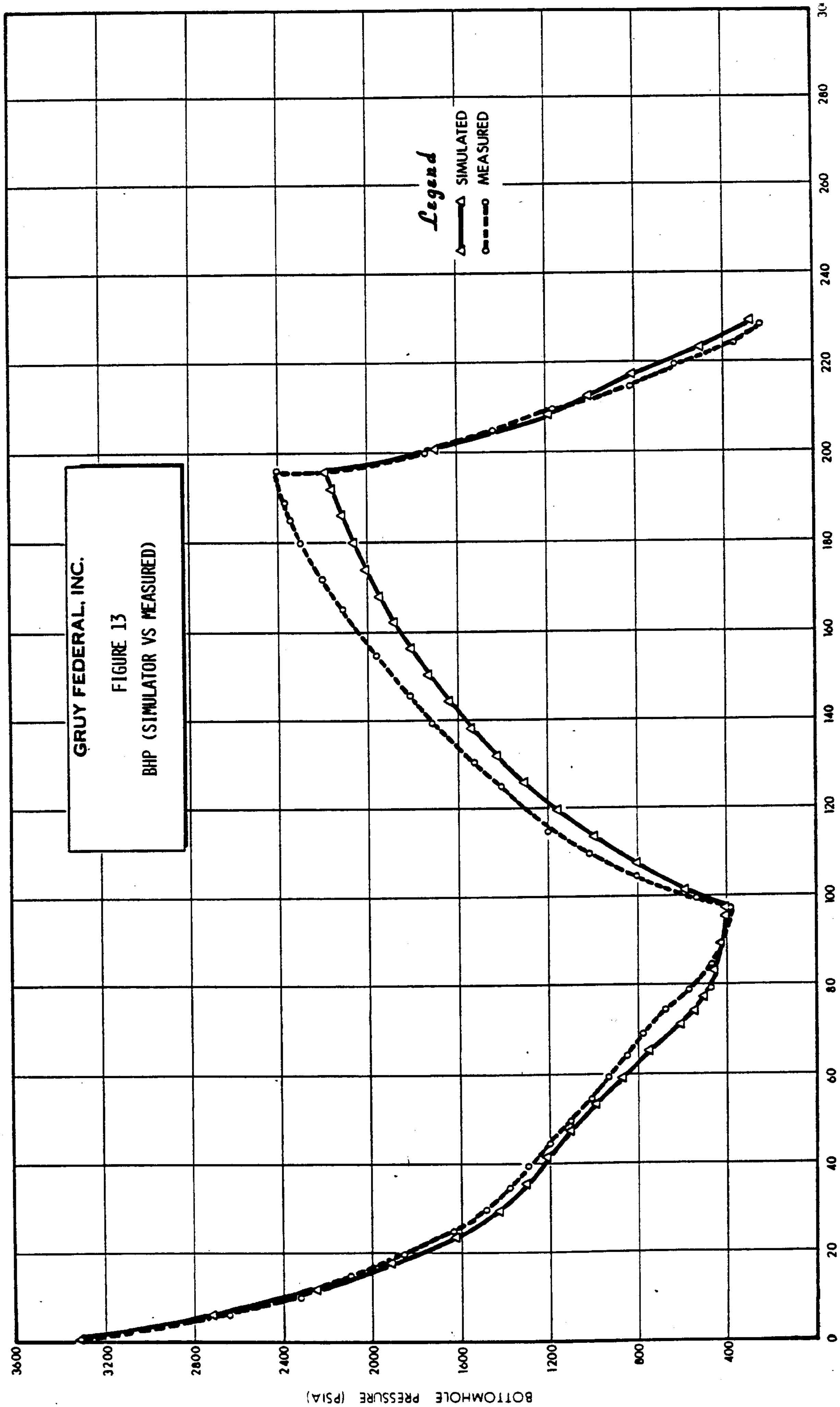

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FIGURE 13
BHP (SIMULATOR VS MEASURED)
Legend
SIMULATED
MEASURED
TIME (HRS)
BOTTOMHOLE PRESSURE (PSIA)
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
400
800
1200
1600
2000
2400
2800
3200
3600

TABLE 3

RESERVOIR PROPERTIES USED IN HISTORY MATCH

RESERVOIR

Effective porosity	0.95%
Effective permeability	0.005 md
Pay thickness (upper zone)	20 ft
Pay thickness (lower zone)	None

FRACTURE

Fracture half-length (upper zone)	62 ft
Fracture half-length (lower zone)	None
Fracture porosity	33%
Fracture permeability	500,000 md
Fracture height (upper zone)	20 ft
Fracture height (lower zone)	None
Fracture width	0.1 in.

the perforated interval; hence there is a possibility of losing sand above the zone of interest. In the absence of a radioactive tracer log, it is difficult to be certain.

To ascertain whether a longer fracture with low finite conductivity had been created in this well, another run was made for Case I, holding the fracture half-length constant at 300 feet and reducing the fracture permeability until a satisfactory match of the measured data was obtained. Fracture permeability and porosity had to be reduced to 1 millidarcy and 10 percent, respectively. A fracture permeability of 1 millidarcy is unrealistic unless the fracture has collapsed.

Deliverability Projection

Using the model obtained by history matching, deliverability projections were made assuming that the well flows into a 40-psig gathering system (see Figure 14). Since the drainage area of these wells is unknown, the projections are limited to 5 years using 160-acre spacing.

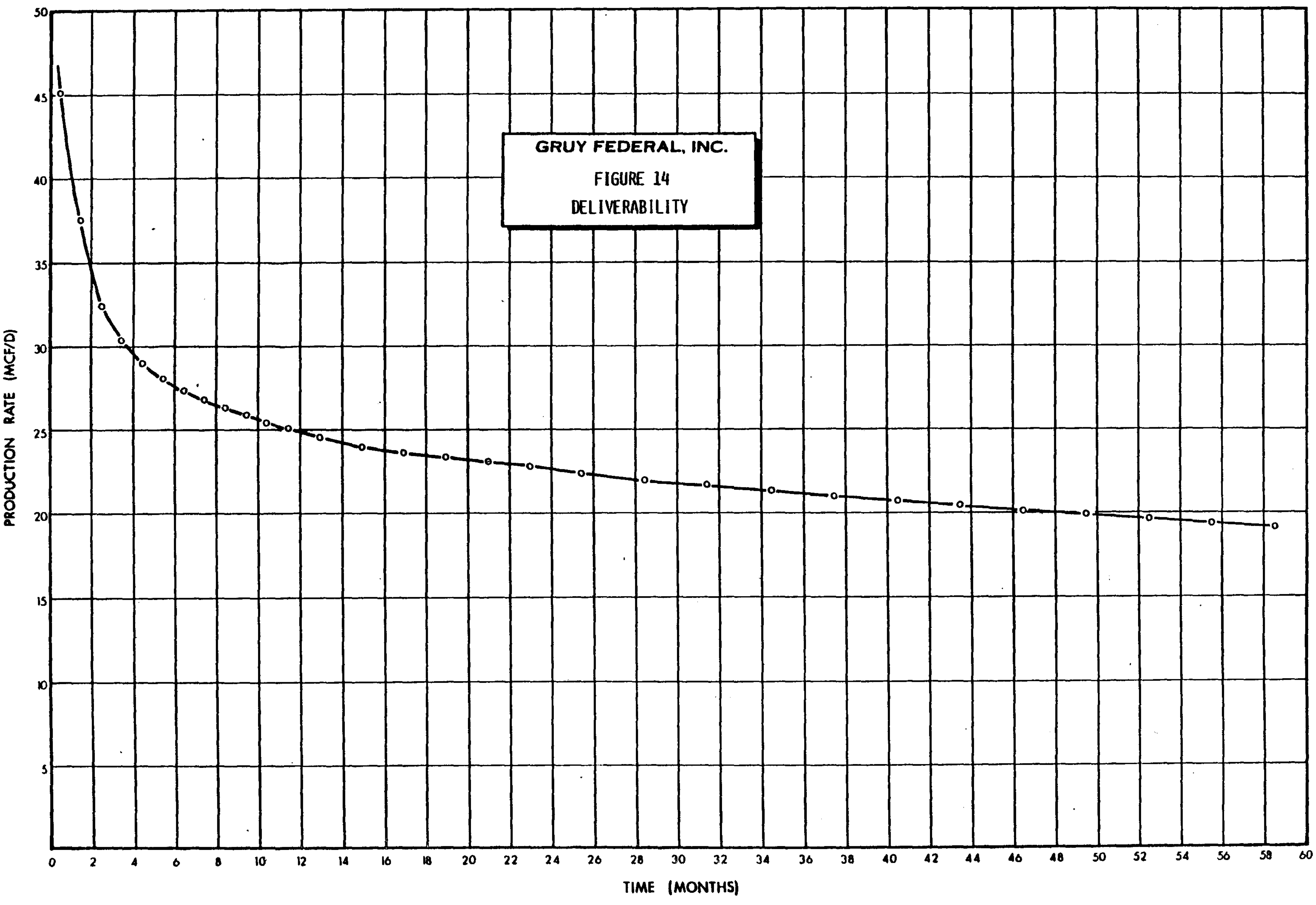
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FIGURE 14
DELIVERABILITY
PRODUCTION RATE (MCF/D)
TIME (MONTHS)
0 5 10 15 20 25 30 35 40 45 50
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32 34 36 38 40 42 44 46 48 50 52 54 56 58 60

CONCLUSIONS

1. Almost all of the gas production can be attributed to the upper zone (Burkett).

2. Extensive natural fracture systems exist in both the upper and lower zones. The bulk of the sand, however, appears to have created fractures in non-productive intervals. Fractures created within the productive intervals lie in the range of 20 to 63 feet.

3. Maximum storage was seen during the buildup because of the large pressure drop during the preceding drawdown. Storage was more dominant in the first drawdown.

4. On the basis of sensitivity analyses, it is obvious that the reservoir configuration of Case IV is more representative of the actual situation.

5. Turbulence effects were negligible.

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NOMENCLATURE

C_t = total system compressibility (psi^{-1})

T_f = formation temperature (°R)

h = formation thickness (ft)

h_f = fracture thickness (ft)

k_g = effective permeability to gas (md)

$m(p)$ = real gas pseudo-potential (psi^2/cp)

ϕ_g = gas filled porosity

μ_g = gas viscosity (cp)

x_n = superimposed time rate data

$$= q_i \sqrt{t_n} - \sum_{i=2}^{n} (q_{i-1} - q_i) \sqrt{t_n - t_{i-1}} \text{ for linear flow}$$

$$= q_i \log t_n - \sum_{i=2}^{n} (q_{i-1} - q_i) \log(t_n - t_{i-1}) \text{ for radial flow}$$

q_i = ith flow rate

t_i = total elapsed time until ith flow rate

x_f = fracture half-length

K_a = apparent permeability (md)

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VOLUME II

Submitted to
U.S. Department of Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

by

GRUY FEDERAL, INC.
2500 Tanglewilde, Suite 150
Houston, Texas 77063

January 4, 1980

COMPANY	-	Gruy Federal, Inc.
OPERATOR	-	C. E. Power Systems Group
DATE	-	October 4, 1979 to October 14, 1979
FIELD	-	Allegheny County, Pennsylvania
WELL	-	C. E. Power Systems Group #1
FORMATION	-	Devonian

Date and Time	Surface Pressure (Psia)	Static Pressure on Orifice Meter (Psig)	Differential on Orifice Meter (inches of water)	Separator Temp. °F	Remarks
10-4-79					
11:00	2727.05				Choke @ 2/64"
:30	2709.21				Orifice Plate = 0.5"
12:00	2627.78				
:30	2582.19				
13:00	2514.88				
:30	2456.77				
14:00	2440.56				
:30	2410.38				
15:00	2373.88	250	46	125	
:30	2331.44				
16:00	2288.70	250	50	125	
17:30	2169.71				
18:00	2126.71	250	40	130	
19:00	2058.09	250	43	90	Choke @ 3/64
:30	2010.34				
20:00	1964.29	260	42	95	
:30	1935.14				
21:00	1906.61	260	42	95	
22:00	1880.25	255	42	100	
24:00	1794.52	275	10	100	Choke @ 4/64
10-5-79					
01:00	1757.29	265	12	110	
02:00	1720.28	280	15	130	
03:00	1685.62	270	15	125	
04:00	1645.20	270	15	105	
05:00	1607.54	270	15	105	
06:00	1568.29	270	15	100	
07:00	1530.35	270	15	100	
08:00	1494.29	265	15	95	
09:00	1458.63	255	16	95	
10:00	1422.23	255	15	97	
11:00	1386.74	255	16	95	
12:00	1350.29	260	16	95	Bumped choke
13:00	1295.72	255	20	100	
15:00	1250.69	250	19	100	
17:00	1215.29	255	18	100	
19:00	1178.69	250	18	100	
21:00	1162.68	250	15	100	Bumped choke
23:00	1145.18	250	17	95	
10-6-79					
01:00	1113.75	250	16	95	
03:00	1085.29	250	16	90	
05:00	1048.69	250	13	90	
07:00	1016.28	250	13	100	Choke @ 5/64
08:00	1000.50	250	14	105	
09:00	960.82	250	14	105	
13:00	920.96	255	12	105	
18:00	870.61	255	15	105	
23:00*	780	250	6	80	Bumped choke back and forth as it was getting plugged
10-7-79					
04:00	700	250	6	95	
09:00	660	255	20	90	
14:00	575	250	13	90	
19:00	480	250	8	100	
24:00	400	215	8	130	

* Pressures beyond this point were recorded by Amerada RPG-6 and are in psig

Date and Time	Surface Pressure (Psig)	Static Pressure on Orifice Meter (Psig)	Differential on Orifice Meter (inches of water)	Separator Temp. °F	Remarks
10-8-79					
05:00	360	255	6	130	Bumped choke
10:00	340	255	6	125	
13:00	325	255	6	120	Shut-in well
:30	350				Start buildup
14:00	390				
:30	430				
15:00	457				
:30	472				
16:00	490				
:30	519				
17:00	545				
:30	570				
18:00	595				
:30	620				
19:00	640				
:30	660				
20:00	687				
:30	720				
21:00	742				
:30	764				
22:00	781				
:30	790				
23:00	800				
:30	809				
24:00	826				
10-9-79					
01:00	859				
02:00	888				
03:00	920				
04:00	960				
05:00	970				
06:00	982				
07:00	996				
08:00	1012				
09:00	1029				
10:00	1044				
11:00	1060				
12:00	1082				
13:00	1104				
14:00	1128				
15:00	1150				
16:00	1173				
17:00	1195				
18:00	1216				
19:00	1236				
20:00	1258				
21:00	1280				
22:00	1299				
23:00	1315				
24:00	1330				
10-10-79					
01:00	1344				
02:00	1360				
03:00	1374				
04:00	1390				
05:00	1402				
06:00	1420				
07:00	1430				
08:00	1444				
09:00	1458				
10:00	1472				
11:00	1486				

Date and Time	Surface Pressure (Psig)	Static Pressure on Orifice Meter (Psig)	Differential on Orifice Meter (inches of water)	Separator Temp. ^{o}F	Remarks
10-10-79					
12:00	1500				Well shut-in
14:00	1520				
16:00	1542				
18:00	1565				
20:00	1594				
22:00	1630				
24:00	1654				
10-11-79					
02:00	1678				
04:00	1705				
06:00	1730				
08:00	1749				
10:00	1770				
12:00	1788				
14:00	1807				
16:00	1825				
18:00	1843				
20:00	1862				
22:00	1890				
24:00	1914				
10-12-79					
02:00	1925				
04:00	1932				
06:00	1940				
08:00	1951				
10:00	1965				
12:00	1974				
14:00	1980				
15:00	1984				Opened well @ 2/64" choke
15:30	1839				
16:00	1762	230	44	150	
17:00	1610	230	44	135	
18:00	1492	210	43	135	
19:00	1438	195	38	130	
20:00	1370	190	34	120	
21:00	1330	200	31	120	
22:00	1260	195	29	120	
23:00	1220	200	20	90	
24:00	1200	200	20	100	
10-13-79					
01:00	1155	200	20	90	
02:00	1110	200	20	95	
03:00	1070	200	20	95	
04:00	1030	200	13	95	
05:00	980	200	11	95	Bumped choke @ 4/64"
06:00	860	200	23	95	
07:00	820	200	10	100	Choke @ 5/64"
08:00	812	200	10	120	Choke @ 7/64"
09:00	808	110	18	90	
10:00	695	100	18	95	
11:00	675	100	19	95	
13:00	600	100	19	95	
14:00	575	100	20	95	
15:00	525	95	18	95	
16:00	455	100	18	100	Choke @ 11/64"
17:00	432	100	23	95	
18:00	410	100	14	95	Choke @ 12/64"
19:00	320	100	8	100	
20:00	300	96	14	110	
21:00	250	90	12	100	
23:00	210	90	10	100	