DATE IN 9.27.04	SUSPENSE	ENGINEER Catanach	LOGGED IN 9.28.04	TYPE IPI	APP NO. pSEM0427232531

ABOVE THIS LINE FOR DIVISION USE ONLY

NEW MEXICO OIL CONSERVATION DIVISION
- Engineering Bureau -
1220 South St. Francis Drive, Santa Fe, NM 87505

243

ADMINISTRATIVE APPLICATION CHECKLIST

THIS CHECKLIST IS MANDATORY FOR ALL ADMINISTRATIVE APPLICATIONS FOR EXCEPTIONS TO DIVISION RULES AND REGULATIONS WHICH REQUIRE PROCESSING AT THE DIVISION LEVEL IN SANTA FE

Application Acronyms:

[NSL-Non-Standard Location] [NSP-Non-Standard Proration Unit] [SD-Simultaneous Dedication]
[DHC-Downhole Commingling] [CTB-Lease Commingling] [PLC-Pool/Lease Commingling]
[PC-Pool Commingling] [OLS - Off-Lease Storage] [OLM-Off-Lease Measurement]
[WFX-Waterflood Expansion] [PMX-Pressure Maintenance Expansion]
[SWD-Salt Water Disposal] [IPI-Injection Pressure Increase]
[EOR-Qualified Enhanced Oil Recovery Certification] [PPR-Positive Production Response]

[1] **TYPE OF APPLICATION** - Check Those Which Apply for [A]

[A] Location - Spacing Unit - Simultaneous Dedication
☐ NSL ☐ NSP ☐ SD

Check One Only for [B] or [C]

[B] Commingling - Storage - Measurement
☐ DHC ☐ CTB ☐ PLC ☐ PC ☐ OLS ☐ OLM

[C] Injection - Disposal - Pressure Increase - Enhanced Oil Recovery
☐ WFX ☐ PMX ☐ SWD ☑ IPI ☐ EOR ☐ PPR

[D] Other: Specify ______________________

[2] **NOTIFICATION REQUIRED TO:** - Check Those Which Apply, or ☐ Does Not Apply

[A] ☐ Working, Royalty or Overriding Royalty Interest Owners

[B] ☐ Offset Operators, Leaseholders or Surface Owner

[C] ☐ Application is One Which Requires Published Legal Notice

[D] ☐ Notification and/or Concurrent Approval by BLM or SLO
U.S. Bureau of Land Management - Commissioner of Public Lands, State Land Office

[E] ☐ For all of the above, Proof of Notification or Publication is Attached, and/or,

[F] ☐ Waivers are Attached

[3] **SUBMIT ACCURATE AND COMPLETE INFORMATION REQUIRED TO PROCESS THE TYPE OF APPLICATION INDICATED ABOVE.**

[4] **CERTIFICATION:** I hereby certify that the information submitted with this application for administrative approval is **accurate** and **complete** to the best of my knowledge. I also understand that **no action** will be taken on this application until the required information and notifications are submitted to the Division.

Note: Statement must be completed by an individual with managerial and/or supervisory capacity.

Print or Type Name	Signature	Title	Date
		e-mail Address	

North America Upstream
MidContinent Business Unit
15 Smith Road
Midland, TX 79705-5412
Tel 432-687-7758
Fax 432-687-7871
davidsmith@chevrontexaco.com

David J. Smith, PE
Sr. Petroleum Engineer

RECEIVED

SEP 27 2004

OIL CONSERVATION DIVISION

ChevronTexaco

September 22, 2004

New Mexico Oil Conservation Division
1220 South St. Francis Drive
Santa Fe, New Mexico 87505
Attention: Mr. David R. Catanach

Re: Request for Increase in Surface Injection Pressure Limit
Central Vacuum Unit Well #84
1333' FSL and 151' FEL, Unit Letter I, Section 36, T17S, R34E
Lea County, New Mexico

Dear Mr. Catanach,

ChevronTexaco requests permission to increase the surface injection pressure limits on CVU #84 (API # 30-025-25732) of 1570 psig for water and 1850 psig for CO2 injection, which is the maximum we have requested for CVU CO2 injectors (note: current surface injection limits are 1450 psig water and 1800 psig CO2). This request is based upon a step rate test conducted on April 8, 2004 by Precision Pressure Data, Inc

Both surface and bottom hole pressure readings were recorded throughout the test and lease water was used as the fluid agent. The bottom hole pressure tool and 42' of 1.375" sinker bars was unable to pass through the packer profile nipple (at 4250'). The pressure tool was pulled up hole and set at 4190' during the test (bottom of sinker bars was 4232'). The obstruction in the packer profile causes the test data to appear inconclusive when looking at standard pressure vs. rate plots. The pressure vs. rate plot shows a continual increase in pressure as rate increases without ever seeing a break.

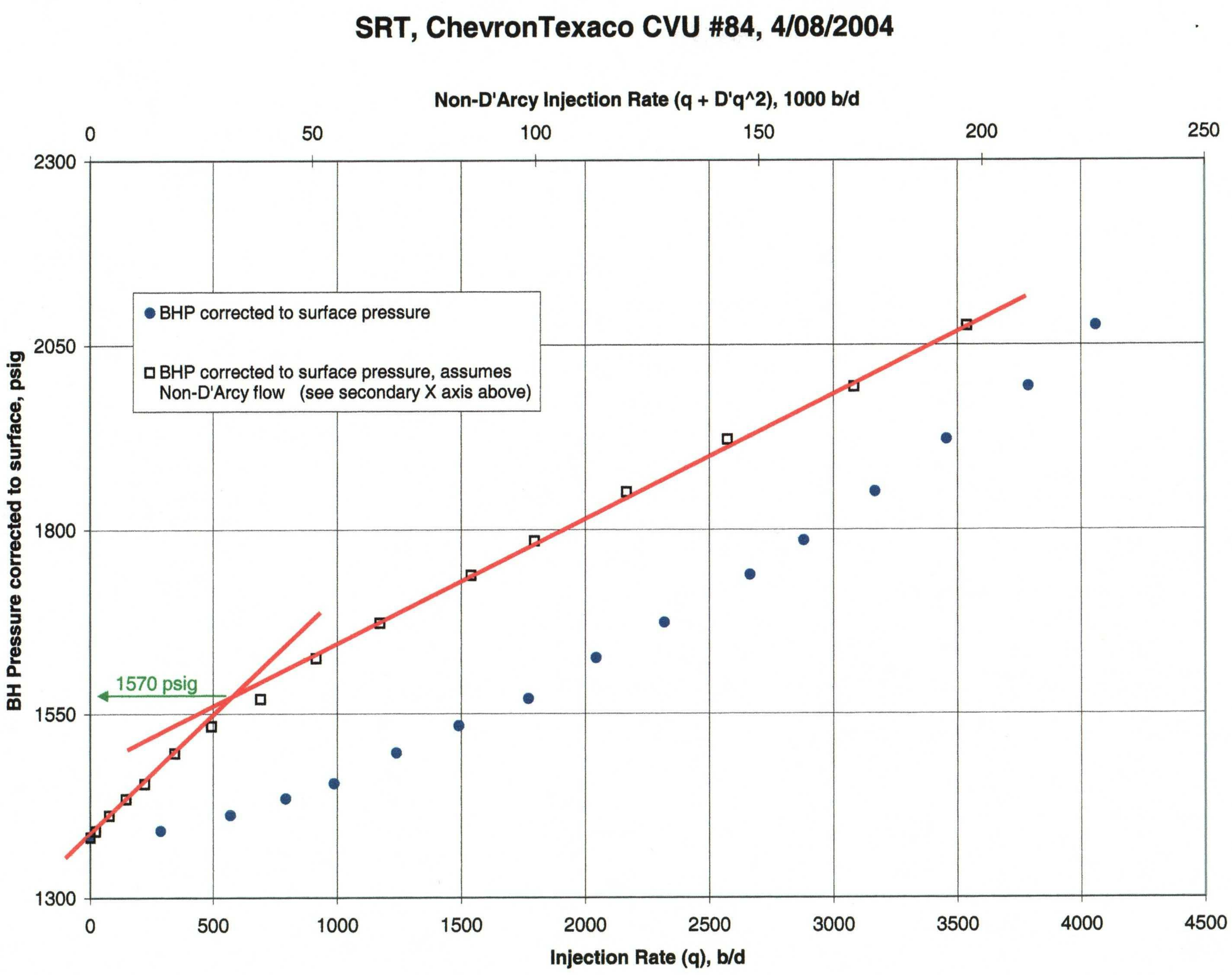
An explanation for this is non-D'Arcy flow downstream from the pressure tool caused by a large pressure drop (in our case the obstruction in the packer profile). Technical literature suggests that a step rate test, where non-D'Arcy flow is occurring downstream of the pressure measuring device, can be evaluated by plotting pressure vs. $q + Dq^2$. (A method for determining D is given in the appendix of the attached technical paper, "Step-Rate Tests Determine Safe Injection Pressures in Floods" by Martin Felsenthal, The Oil and Gas Journal – October 28, 1974.) Per the papers guidelines I plotted the bottom hole pressure converted to surface (by backing out the hydrostatic head) vs. $q + Dq^2$ on the secondary X axis. Using this method a clear break is observed at a surface pressure of 1570 psig. (The pressure vs. rate data is also on plot, but a break cannot be seen.) This plot and other test data are attached.

Thank you for your consideration. Please call me at 432-687-7758 if you have questions or concerns.

Sincerely,

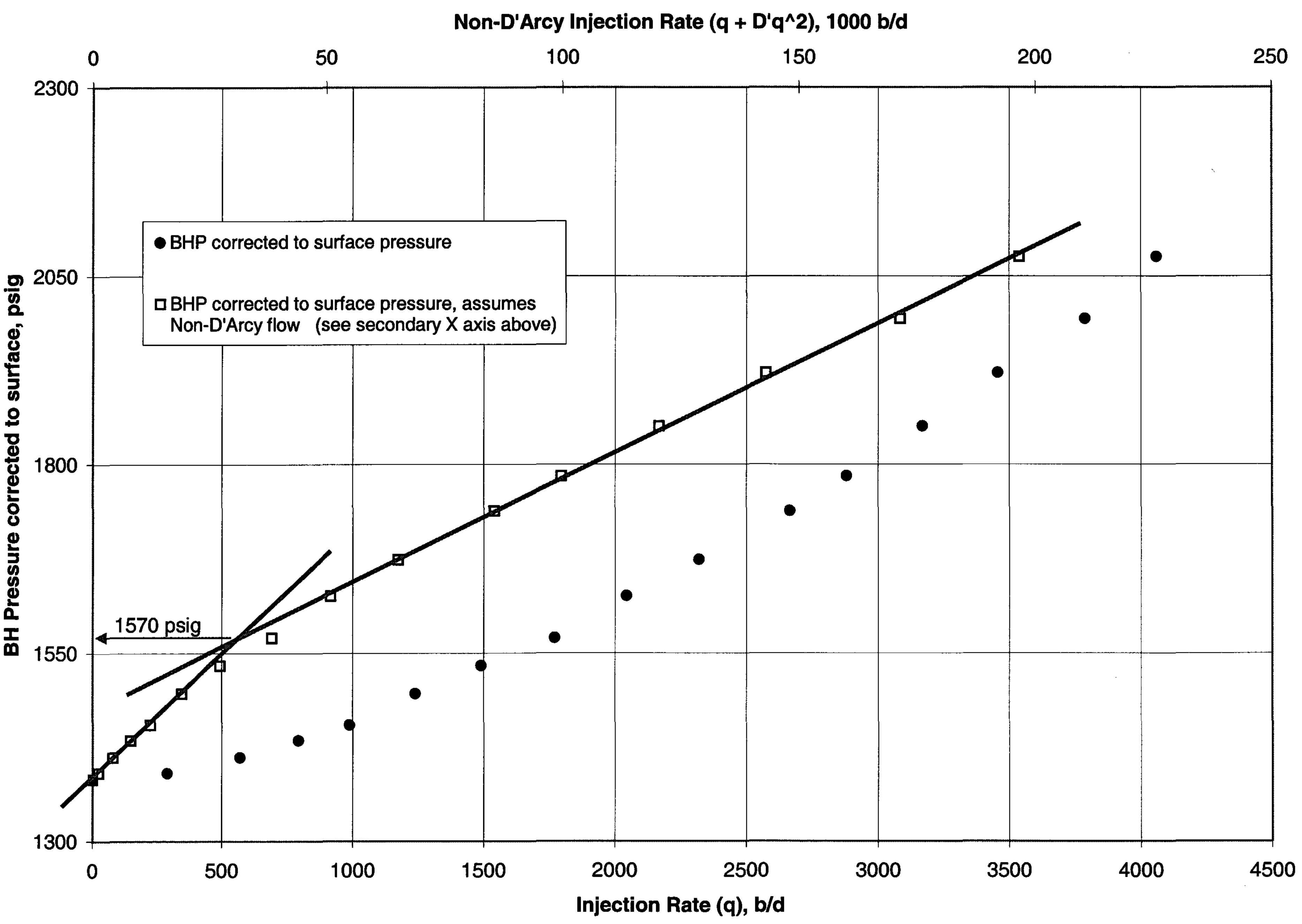
David J. Smith

David J. Smith, PE
Sr. Petroleum Engineer



SRT, ChevronTexaco CVU #84, 4/08/2004
Non-D'Arcy Injection Rate (q + D'q^2), 1000 b/d
0
50
100
150
200
250
2300
2050
1800
1550
1300
BH Pressure corrected to surface, psig
BHP corrected to surface pressure
BHP corrected to surface pressure, assumes Non-D'Arcy flow (see secondary X axis above)
1570 psig
0
500
1000
1500
2000
2500
3000
3500
4000
4500
Injection Rate (q), b/d

SRT, ChevronTexaco CVU #84, 4/08/2004



Step-rate tests determine safe injection pressures in floods

The author . . .

Martin Felsenthal is a senior research engineer with Continental Oil Co. in Ponca City, Oklahoma. He works in the areas of formation evaluation, waterflooding and tertiary recovery. A petroleum engineering graduate from University of California, he also holds an MS from Penn state.

Felsenthal

STEP-RATE injectivity tests can define the maximum safe injection pressures that can be used without fracturing the reservoir rock.

This information is important in waterfloods. It is of critical importance in tertiary-recovery projects where we cannot afford to lose costly injection fluids through uncontrolled induced fractures.

Recently, we tried the step-rate test in a number of projects. Although the test concept is simple, results were conclusive only if proper procedures and equipment were used. From this experience, a recommended procedure has been developed.

This article presents the recommended procedure and shows typical data.

A remarkable point brought out by these data is that formations sometimes fracture near hydrostatic head in pressure-depleted reservoirs.

The procedure. The early literature references [1,2] generally talked about pressure parting rather than fracturing during step-rate injectivity tests. It was pointed out, however, at the outset that the two expressions are synonymous.

The test well should be shut in long enough so that the bottom-hole pressure is near the shut-in formation pressure. The step-rate injectivity test that follows consists of a series of constant-rate injections with rates increasing from low to high in stepwise fashion.

In tight formation ($K_{air} \sim 5$md) each step should last 60 min. Shorter time spans can be used in higher-permeability formations as shown in Table 1 of the appendix. The time-step duration itself is not critical. It only should be reasonably close to the recommended values shown. Also, each step should last exactly as long as the preceding step.

In selecting rates for the test, one possible rule of thumb is to use 5, 10, 20, 40, 60, 80, and 100% of the desired maximum test rate. The above schedule may be varied to suit the conditions of the test. For instance, it may be difficult to control accurately a very low rate in which case, the test may be started at a somewhat higher rate than shown above.

Equipment. Injection rates during the test should be controlled with a constant flow-rate regulator. We have used regulators made by three different companies and obtained useful data. All regulators should be tested before use.

Use of a throttling valve as a flow-rate regulating device is not recommended. Reason is that this valve acts like an orifice. Pressures and rates will thus interact continuously during the transient flow conditions of each rate step. Consequently, as well pressures rise, injection rates will tend to decline.

Flow rates should be measured with a turbine flowmeter and a rate meter such as those made by Halliburton. It is advisable to calibrate this equipment by timing flow into a 5-gal container (b/d = 10,286 ÷ seconds to fill a 5-gal container).

In critically important tests, it is advisable to record rates throughout the test. For this purpose, we have fed a signal from a rate meter through a dampening circuit to a strip-chart recorder. Use of a rate recorder is desirable but not mandatory.

Our experience has shown that best results were obtained when pressures were measured with a down-hole instrument. For instance, we used

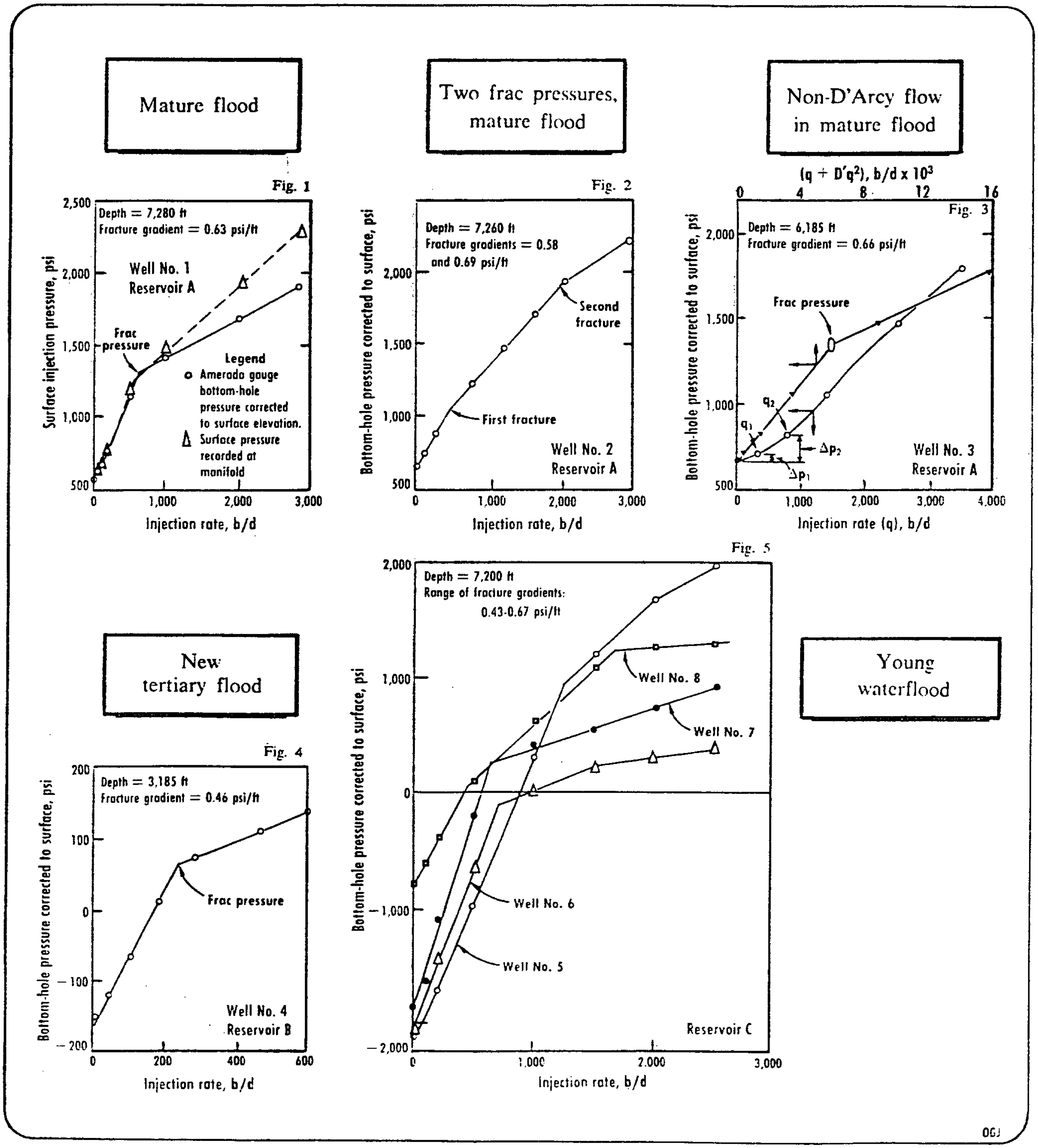
Amerada-type pressure-recording devices in all tests shown in Figs. 1-5. Other down-hole devices may be equally suitable. In addition, it is advisable to observe surface pressures with a surface gage or recorder. We found that it is often difficult to obtain very accurate surface-pressure readings because of surges from the injection pump. Nevertheless, surface pressures are useful in many tests for on-the-spot analysis, while the test is in progress. Final test analysis, however, should be based on down-hole pressure data.

Data analysis. The pressures at the start of the test (at q = 0) and at the end of each injection-rate step are plotted against injection rates as in Fig. 1. Shown are down-hole pressures corrected to the surface elevation of the well and pressures recorded at the surface. The difference in the two pressures is mainly due to friction losses in the pipes.

When the data show that it takes a smaller pressure increment for a unit-rate change, we generally infer that fracturing has taken place. Thus, the data of Fig. 1 indicate that Well

Figs. 1-5

Step-rate tests on old and new floods



No. 1 fractured at about 1,300 psi surface pressure.

Sometimes two breaks are indicated in the pressure-vs-rate plots. Each break could represent a separate fracture. For instance, data for Well No. 2 (Fig. 2) indicate a first fracture at a surface pressure of 1,050 psi and a second and more-severe fracturing condition at 1,900 psi.

Occasionally, pressure-vs-rate plots do not form a straight line but form a curve with a distinctive upward curvature near the origin as shown in Fig. 3. The best explanation for this is non-D'Arcy flow downstream from the pressure-measuring device. This implies that there is probably a sizable pressure drop across the perforations or other orifice-like obstructions. An added resistance is created that is proportional to the square of the injection rate. Thus, we observed we could not interpret the step-rate data for Well No. 3 from a standard pressure-vs-rate (q) plot but could do so from a plot of pressure vs. $q + Dq^2$ (A method for determining D is given in the appendix). Data in Fig. 3 indicate that the fracturing pressure was about 1,300 psi in Well No. 3.

In some pressure-depleted reservoirs, initial pressures are lower than hydrostatic head. Such a situation occured during the tests illustrated in Figs. 4 and 5. Down-hole rates at the end of the early steps were somewhat smaller in these tests than rates measured at the surface because of rising fluid levels in the wells. Appropriate corrections for this condition had to be made before the data could be analyzed.

Complementary techniques. Pressure-falloff tests are generally a good source of information on permeability capacity, probable presence of fractures, skin and nearness to faults or barriers.[4] An excellent opportunity generally exists for conducting this type of test while the test well is being shut in before step-rate testing. If the skin calculated from such a test is definitely negative, we can infer that we probably have a fracture. One way to find out whether the fracture is natural or induced is to reduce the injection pressure for some time, say 1 month, and then run another pressure-falloff test. If the skin is closer to zero in the second test, we can conclude that an induced fracture tended to close.

Permeability capacity and skin (before fracturing) can also be evaluated directly from step-rate test data using a multiple-rate flow-test analysis technique.[3,4] A prerequisite to this technique is great care to keep rates constant in each step and to obtain accurate data. Use of the technique is illustrated in the appendix.

Step-rate tests and pressure-falloff tests give virtually no information about fluid-injection distribution. For diagnosing the formation characteristics near injection wells, in a vertical dimension, injectivity-profile tests are needed. These tests are very useful and popular. Results obtained from them can beneficially supplement results obtained from step-rate and pressure-falloff tests. Especially helpful for this purpose are radioactive tracer injection and/or temperature decay surveys (Absolute temperature profile while injecting, followed by absolute temperature profiles after shutin of injection).

Typical data. Typical pressure-vs-rate plots are shown in Figs. 1-5. The remarkable feature brought out by the last two figures is that the fracturing pressure was near hydrostatic head for most of the wells tested in the pressure-depleted reservoirs B and C. It was even slightly below the hydrostatic head in one well (No. 6, Fig. 5).

To place the data presented so far into perspective, a plot of fracturing gradients vs. shut-in formation pressure/depth ratios was prepared for wells from six formations. The resulting graph (Fig. 6) covers a wide range of prior injection histories, lithology, depths, geographic distribution (five states), geologic ages (Mississippian to Pliocene), and shut-in formation pressure/depth ratios.

Note that fracturing gradients ranged from 0.43 psi/ft to 0.93 psi/ft with the higher gradients generally occurring at the higher shut-in formation pressure/depth ratios. This trend of increasing fracturing gradients with shut-in formation pressure is in agreement with observations reported in several literature references.[5-8] This trend is especially well illustrated in Fig. 6 by the data for reservoir D (solid circles denote data taken in the first month of the flood and open circles denote data taken in the same wells 6 months later). These data indicate that fracturing pressures should be reevaluated periodically.

Vertical arrows in Fig. 6 connect first fracturing indications with second fracturing indications during the same test in the same well. (Details for Well No. 2 are shown in Fig. 2 and for Well Nos. 5, 6, and 8 in Fig. 5.) A preferred interpretation for this is that a first fracture occurred in comparatively hard, brittle rock and a second fracture in softer and more plastic rock.

The dashed lines shown in Fig. 6 show a comparison with a prevalent fracturing theory[6,7] (explained in the appendix). This presentation does not exclude the possibility that a refinement of this theory or some other theory would result in a better fit of the curves and data points.

Numbers on the dashed lines in Fig. 6 are Poisson's ratios. It has been speculated in the literature[8] that data points coinciding with relatively high Poisson's ratios (greater than 0.35) might be indicative of fracture extension through plastic cap-rock shales. This view is unconfirmed, however, at this time, because injectivity profiles, particularly temperature-decay surveys, were not made at the time (or close to the time) when the step-rate tests associated with high Poisson's ratios were made.

Will test damage formation? A study of field records for injection Wells Nos. 1-8 (Figs. 1-5) showed that earlier injection pressures exceeded the maximum pressure used during the step-rate tests. The theory of rock mechanics indicates that fractures once opened will tend to close again when the injection pressure is reduced below the fracturing pressure. What is happening is that the net effect of the overburden becomes stronger than the force that tends to keep an unpropped, induced fracture open. This is the mechanism that apparently occurred before step-rate testing in Wells Nos. 1-8.

No damage can conceivably be caused by step-rate tests in old waterfloods as long as the injection pressure during the tests does not exceed injection pressures used earlier during the waterflood history and as long as high-quality injection water is used. In a new waterflood, a typical well should be selected for a step-rate test. In this well, one should use only low and moderate injection rates until a fracturing pressure is definitely established. Later tests should be designed so that they do not greatly exceed this pressure for any appreciable length of time (more than a few hours).

Acknowledgments

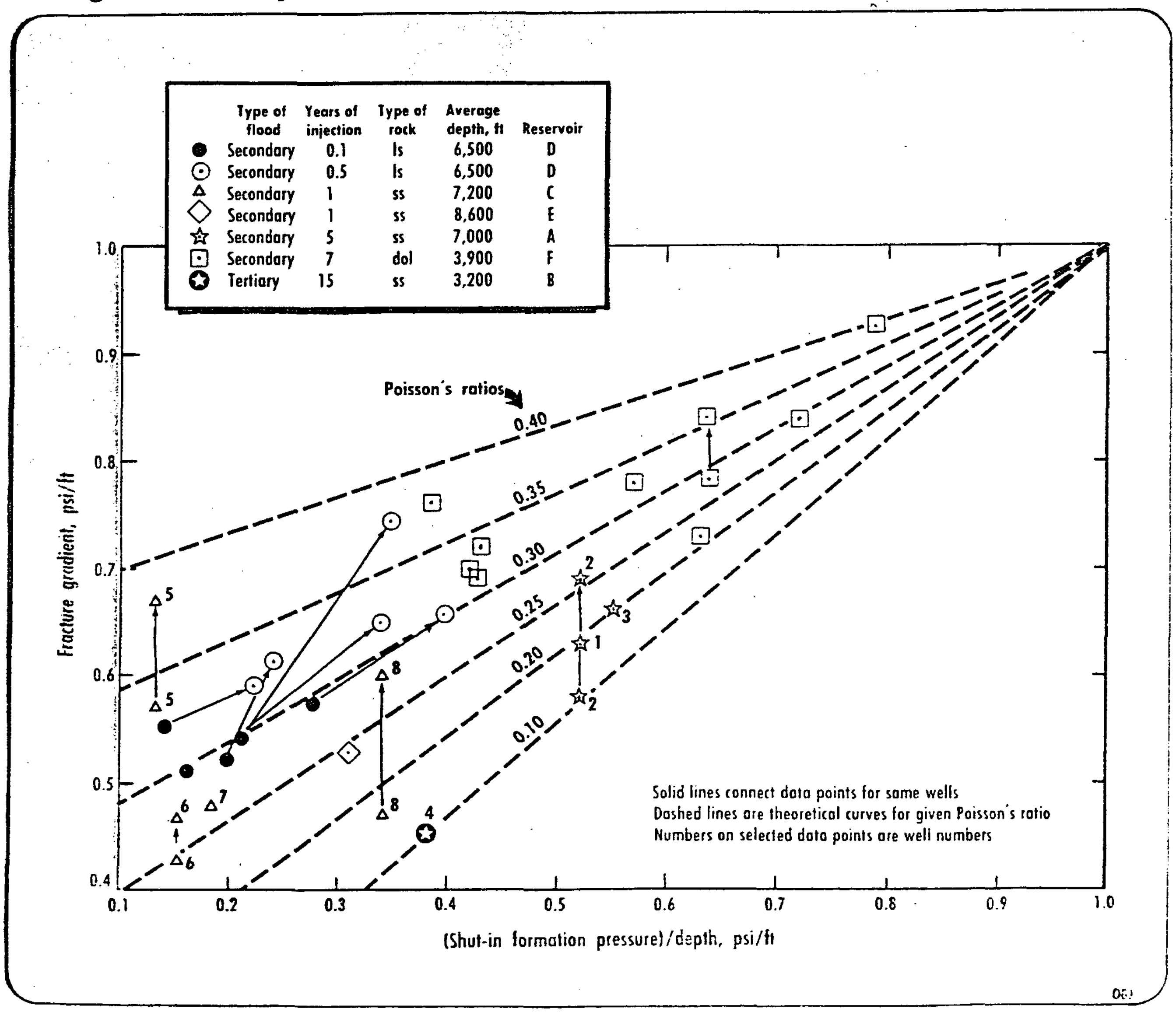
I am indebted to H. C. Walther for guidance and constructive criticisms, to H. A. Wahl for valuable suggestions, and to R. C. Cooper, Wayland Edwards, Dell Conley, and R. A. Strode for assistance in data collection and analysis.

Nomenclature

b' = Odeh intercept
B = Constant, psi/(b/d)^2
B_W = Water formation volume factor, RB/st-tk bbl
c = Total compressibility, psi^{-1}
C = Constant, (b/d)/psi
D = Non-D'Arcy flow constant, (b/d)$^{-1}$
D' = Another non-D'Arcy flow constant related to D as explained in equation 5, (b/d)$^{-1}$
h = Net effective pay, ft
K_{air} = Absolute permeability to air, md
k_{rW} = Relative permeability to water
k_w = Effective permeability to water, md
m' = Odeh slope
n = Step number in step-rate test
p = Pressure during step-rate test at time t, psi
p_e = Shut-in formation pressure, psi
P_f = Fracturing pressure related to same elevation as p_e, psi
p_i = True initial pressure during step-rate test, defined by intercept of p vs. q plot when q = o, psi
p_W = Bottom-hole pressure in well, psi
Δp = Difference in pressures, psi
Δp_f = Friction loss through perforations or slots, psi
q = Injection rate, b/d
r_e = Outer radius of pressure influence, ft
r_W = Well-bore radius, ft
r_{We} = Effective well-bore radius, ft
s = Skin factor, dimensionless
s' = Apparent skin factor, dimensionless
S = Overburden pressure, psi
t = Time since start of test, hr.
t_n = Time at end of step n of step-rate test, hr
Z = Depth, ft
Φ = Porosity, fraction
μ_W = Water viscosity, cp
ν = Poisson's ratio, dimensionless

Fig. 6

Frac gradients vs. pressure-depth ratio



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3. Odeh, A. S., and Jones, L. G., "Pressure Drawdown Analysis, Variable-Rate Case," Jour. Pet. Tech., pp. 960-964, August 1965.
4. Matthews, C. S., and Russell, D. G., "Pressure Buildup and Flow Tests in Wells," SPE Monograph, V. 1, 1967.
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7. Eaton, B. A., "Fracture Gradient Prediction and Its Application in Oilfield Operations," Jour. Pet. Tech., pp. 1353-1360, October 1969.
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Appendix

PRESENTED here are recommended step-rate test times, non-D'Arcy flow-analysis techniques, and a multiple-rate analysis technique applied to step-rate tests. Also, presented is a brief description of a fracturing theory used in diagnosing step-rate test data.

Recommended time for each injection-rate step

Radius of investigation, $r_{inv} = \sqrt{0.00105 k_w t/\phi \mu_w c}$ (1)

This radius should be about 10 ft or larger to investigate formation properties adequately. For assumed typical values of $\phi = 0.2$, $\mu_w = 0.7$ cp, $c = 1.5 \times 10^{-5}$ psi^{-1}, $kr_w = 0.05$ for $K_{air} = 5$ md, and 0.10 for $K_{air} > 5$ md, we obtain.

Table 1

Test design values

Average K_{air}	Recommended minimum time for each step
5 md	60 min
10 md and larger	30 min

Non-D'Arcy flow analysis techniques

In non-D'Arcy radial flow:

$$q = \frac{0.00708 k_w h \Delta p}{\mu_w [\ln(r_e/r_w) + s + Dq]} \qquad (2)$$

Where D is the non-D'Arcy flow constant, $(B/D)^{-1}$:

The apparent skin $= s' = s + Dq$ (3)

The s' term can be evaluated through a multiple-rate flow-test analysis technique (described in another part of this appendix) by substituting s' for s in equation 16. Next, s' is plotted vs q for the early steps of the test. D is then determined from this plot with the aid of equation 3. Analyses of s (= s' − Dq) for all steps of the step-rate test follow. The s terms are finally plotted vs injection pressures, and the point at which s becomes greatly more negative is interpreted as the fracturing pressure.

The aforementioned procedure is rather time-consuming. A shortcut approach was, therefore, developed and applied to the data of Well No. 3. This approach gave the same results as the method based on the multiple-rate flow-test analysis technique for this well.

For the derivation of the shortcut formula, Equation 2 was rewritten as

$$q + D'q^2 = C\Delta p \qquad (4)$$

Where:
$C = 0.00708\, k_w h/\mu_w [\ln(r_e/r_w) + s]$

$$D' = D/[\ln(r_e/r_w) + s] \qquad (5)$$

It was assumed here that $\ln(r_e/r_w)$ and C remained virtually constant before fracturing occurred. This is a reasonable assumption as long as q in a given step is much larger than q in the preceding step. Selecting two such steps (before indicated fracturing) as shown in Fig. 3, we wrote

$$q_1 + D'q_1^2 = C\Delta p_1 \qquad (6)$$

$$q_2 + D'q_2^2 = C\Delta p_2 \qquad (7)$$

Dividing (6) ÷ (7) gave:

$$\boxed{D' = (q_2\Delta p_1 - q_1\Delta p_2)/(q_1^2\Delta p_2 - q_2^2\Delta p_1)} \qquad (8)$$

It should be emphasized that D' and D carry the same units, $(b/d)^{-1}$, but are **not** identical. They are related as shown in Equation 5. In the shortcut approach, pressure is finally plotted vs. $(q+D'q^2)$, as shown in Fig. 3.

In an alternate approach to solving the non-D'Arcy flow problem, we start with this equation:

$$q = \frac{0.00708 k_w h(\Delta p - \Delta p_f)}{\mu_w[\ln(r_e/r_w) + s]} \qquad (9)$$

where $\Delta p = p_w - p_e$ and Δp_f is the friction loss which in turn is related to q as follows:

$$\Delta p_f = Bq^2 \qquad (10)$$

In Equation 10, B is a function of the water density and the number and diameter of perforations that are open. Defining C as above, we then obtain from 9 and 10 for two rates, q_1 and q_2, before fracturing,

$$q_1 + BCq_1^2 = C\Delta p_1 \qquad (11)$$

$$q_2 + BCq_2^2 = C\Delta p_2 \qquad (12)$$

It is evident from an analogy to Equations 6 and 7 that BC=D'. It follows that we arrive in effect at the same solution, i.e., Equation 8, regardless of whether we start from Equation 2 or 9.

Multiple-rate flow test analysis

The technique of applying multiple-rate flow-test analysis to step-rate injectivity test data is based on the prin-

Table 2

Step-rate data during early part of test, Well No. 2

t, hr	q, b/d	p, psi	Data point	Step no. n	Odeh sum*	$\Delta p^{\dagger}/q$
0	0	642	–	–	–	–
0.5	100	720	a	1	−0.301	0.780
1.0	100	730	b	1	0	0.880
1.5	250	856	c	2	−0.110	0.856
2.0	250	874	d	2	0.120	0.928
2.25	750	1,143	e	3	−0.335	0.668
2.50	750	1,182	f	3	−0.112	0.720
3.00	750	1,216	g	3	0.124	0.765

*Odeh sum $= [q_1 \log t + (q_2-q_1)\log(t-t_1) + (q_3-q_2)\log(t-t_2) + \ldots + (q_n-q_{n-1})\log(t-t_{n-1})]/q_n$ (13)

†$(p-p_i)/q_n$ (14)

$p_i = 642$ psi

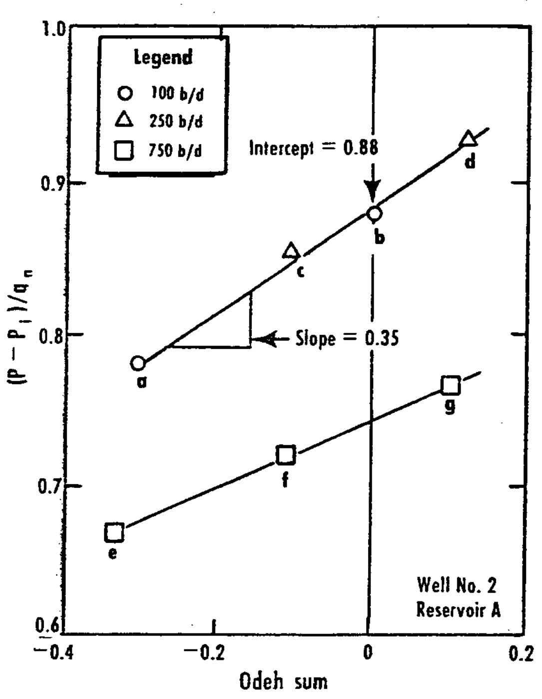
$t_1 = 1.0$ hr; $q_1 = 100$ b/d

$t_2 = 2.0$ hr; $q_2 = 250$ b/d

$t_3 = 3.0$ hr; $q_3 = 750$ b/d

Fig. 7

Odeh method of analysis



Standard step-rate graph as shown in Fig. 2

OGJ

ciple of "superposition." The technique, sometimes called the Odeh method, is well described in the literature for drawdown tests.[3,4] The equations presented in the literature can be used for the analysis of step-rate test data after making a change in sign and a change in symbol notations. Applicable equations and their use are presented in the following paragraphs.

The multiple-rate flow-test analysis technique determines $k_w h$ and skin before fracturing. It is essential that good data are available. Also, the correct initial pressure, p_i, must be known. This is the pressure that represents the intercept of the p vs. q plot when $q=0$. Note, for instance, that using this criterion gives a lower p_i for Well No. 4 (Fig. 4) than indicated by the first observed pressure.

The method can be applied in theory only to data taken during the early rate steps when radial flow is the predominant flow mechanism in the formation zone under investigation. This approach was used for the data of Well No. 2 (Fig. 2). Data for the end of each of the early steps and for one or more arbitrary points during each of these steps were tabulated as shown in the first three columns of table 2, shown at left.

Sample calculations. For data point a (Step 1):

Odeh sum $= q_1 (\log t)/q_1 = 100 (\log 0.5)/100 = -0.301$

$(p-p_i)/q_1 = (720-642)/100 = 0.78$

For data point g (Step 3):

$$\text{Odeh sum} = [q_1 \log t + (q_2-q_1)\log(t-t_1) + (q_3-q_2)\log(t-t_2)]/q_3$$
$$= [100 \log 3 + (250-100)\log(3-1) + (750-250)\log(3-2)]/750$$
$$= 0.124$$

$(p-p_i)/q_3 = (1{,}216-642)/750 = 0.765$

The last two columns of Table 2 were plotted in Fig. 7. From this graph we read slope, $m' = 0.35$, and intercept, $b' = 0.88$. Known also were: $\mu_W = 0.45$ cp, $B_W = 1.0$, $h = 270$ ft (from a radioactive tracer-injectivity survey), $\Phi = 0.186$, $c = 1.5 \times 10^{-5}$ psi^{-1}, and $r_w = 0.25$ ft.

$$k_W h = 162.6 \mu_W B_W / m' \quad (15)$$
$$k_W h = 162.6 \times 0.45 \times 1.0/0.35 = 209 \text{ md ft}$$
$$k_w = 209/270 = 0.77 \text{ md}$$

$$s = 1.151 \left[\frac{b'}{m'} - \log \frac{k_w}{\Phi \mu_W c r_W^2} + 3.23 \right] \quad (16)$$

$$s = 1.151 \left[\frac{0.88}{0.35} - \log \frac{0.77}{0.186 \times 0.45 \times 1.5 \times 10^{-5} \times 0.0625} + 3.23 \right]$$

$s = -1.4$

$$r_{we} = r_w e^{-s} \quad (17)$$

$r_{we} = 0.25 e^{1.4} = 1.0$ ft

The data plotted in Fig. 7 show that the method broke down after point d was measured. That is, the following data points, e, f, and g, fell no longer on the old line. This was interpreted to indicate that radial flow was no longer the predominant flow regime and that fracturing had occurred.

Fracturing theory for diagnosis.

The theory [6,7] used in drawing the dashed lines in Fig. 6 is expressed by the equation:

$$p_f/Z = [(S/Z) - (p_e/Z)]\,[\mu/(1-\mu)] + p_e/Z \quad (18)$$

The Poisson's ratio, ν is the ratio of maximum lateral deformation to maximum longitudinal deformation observed during compression loading of rock samples. A low ratio is generally associated with dense, brittle rock and a higher ratio with more elastic rock. The overburden pressure gradient, S/Z, used in constructing the theoretical curves of Fig. 6, was 1.0 psi/ft of depth. Other terms are defined in the nomenclature.

CURRENT
WELLBORE DIAGRAM

Created:	4/6/2004 **By:** SMG						
Updated:	4/7/2004 **By:** BJH						
Lease:	Central Vacuum Unit	**Well No.:**	84			**Field:**	Vacuum Grayburg San Andres
Surface Location:	1333' FSL & 151' FEL	**Unit Ltr:**	I	**Sec:**	36	**TSHP/Range:**	17S-34E
Bottomhole Location:	Same	**Unit Ltr:**		**Sec:**		**TSHP/Range:**	
County:	Lea **St:** NM	**St Lease:**	857943	**API:**	30-025-25732	**Cost Center:**	
Current Status:	Water Injection Well	**Elevation:**	3985' GL			TEPI:	BCT493000
Directions to Wellsite:	Buckeye, New Mexico					MVP:	BCT494500

Surface Csg.

Size:	13 3/8"
Wt.:	54.5#, K-55
Set @:	355'
Sxs cmt:	400
Circ:	Yes
TOC:	Surface
Hole Size:	17 1/2"

Intermediate Csg.

Size:	9 5/8"
Wt.:	32#, K-55
Set @:	1500'
Sxs Cmt:	800
Circ:	Yes
TOC:	Surface
Hole Size:	12 1/4"

Intermediate Csg.

Size:	7"
Wt.:	23#, K-55
Set @:	2755'
Sxs Cmt:	300 / 350
Circ:	Yes
TOC:	Surface
Hole Size:	8 3/4"

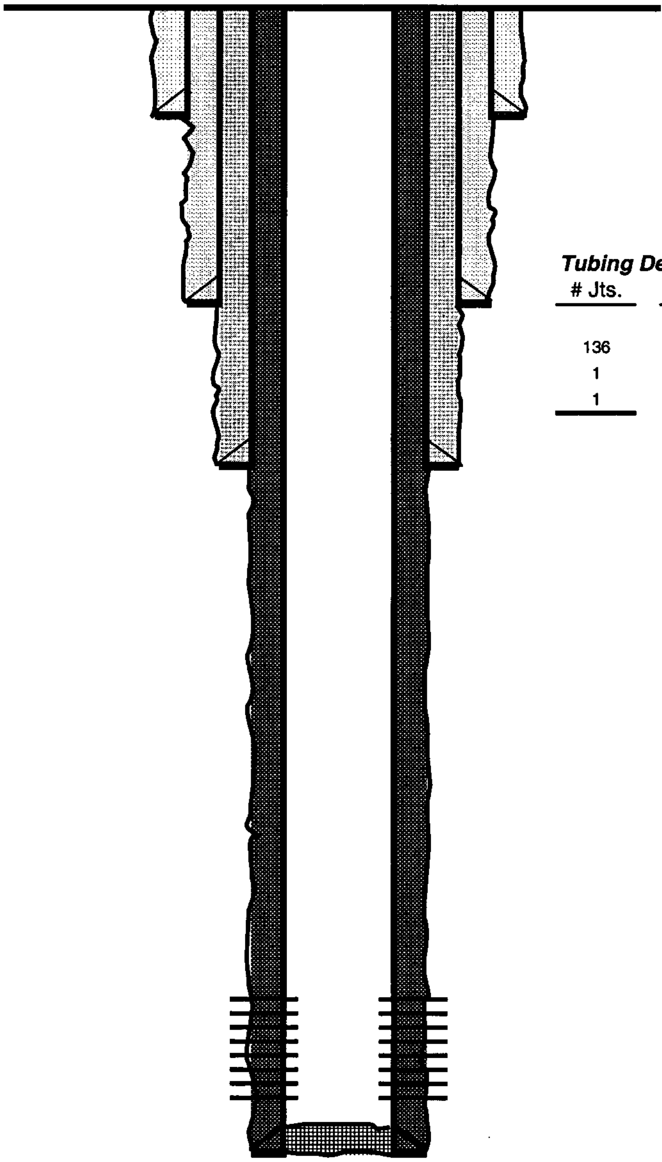
Production Csg.

Size:	4 1/2"
Wt.:	10.5#, K-55
Set @:	4800'
Sxs Cmt:	800
Circ:	Yes
TOC:	Surface
Hole Size:	6 1/8"

TD:	4800'
PBTD:	4790'

Perforations:

Grayburg San Andres, 2 JSPF	4350'-4682'



KB:	
DF:	
GL:	3985'
Original Spud Date:	2/13/1979
Original Compl. Date:	3/23/1979

Tubing Detail **Date:**

# Jts.	Size	Footage
	KB	12.00
136	2 3/8" Duoline Tubing cl. 'B'	4250.34
1	4-1/2" Guiberson G-6 Nickel pl. Pkr	4.46
1	w/ 1.431" F profile nipple	1.97
		4268.77

TD: 4800'

Hobbs District Laboratory

Company:	CVX	Report No.:	Produced - Water
Lease & Well:	CVU 84	Service Point:	HNM LAB
County, State:		Prepared by:	A. Roblez
Formation:		Prepared for:	G. Powell
BHT (F):		Date:	4/8/2004

Specific gravity: 1.058 64 degrees F ph 7.00

Anions

	Factor	ml	Sample	mg/l	Factor	me/l	Ionic Strength (mg/l)	Ionic Strength (me/l)	(ppm)
Chlorides	3545	13.90	1	49276	0.0282	1389.57	0.6899	0.6948	46574
Sulfates	20	200.0	25	160	0.0208	3.33	0.0034	0.0033	151
Carbonates	492	0.7	10	34	0.0333	1.15	0.0011	0.0011	33
Bicarbonates	1000	9.10	10	910	0.0164	14.92	0.0073	0.0075	860

Cations

	Factor	ml	Sample	mg/l	Factor	me/l	Ionic Strength (mg/l)	Ionic Strength (me/l)	(ppm)
Calcium	401	8.9	1	3568.9	0.0499	178.09	0.1784	0.1781	3373
Magnesium	243	2.90	1	704.7	0.0823	58.00	0.0578	0.0580	666
Iron				0	0.0358	0.00	0.0000	0.0000	0
Sodium	0	0	0	26963	0.0435	1172.88	0.5932	0.5864	25485

Total Dissolved Solids: 81616.37 2817.94

Total Ionic Strength: 1.5310 1.5292

Calcium Carbonate Deposition

Stiff-Davis Equation: Stability Index(SI) = pH - pCa - pAlk - K

pH= 7.00
pCa= 1.04
pAlk= 2.08
K= 1.31

Total Ion Equivalent NaCl Concentration= 76944.5 ppm

SI= 2.57

The Stiff-Davis equation predicts this water does have a tendency toward calcium carbonate deposition.

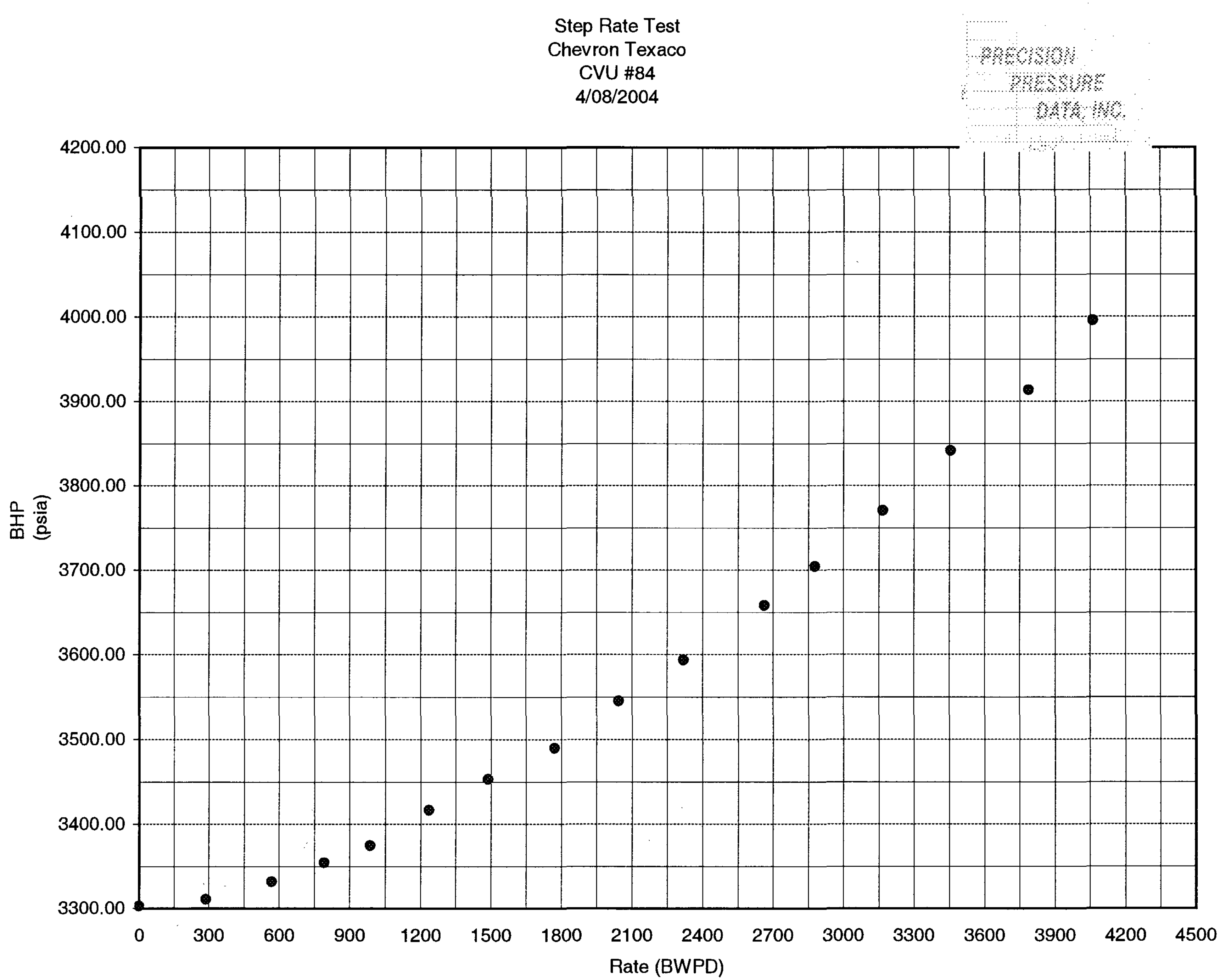
Calcium Sulfate Deposition

CaSO4 Solubility: S = 1000 (SQRT (X**2 + 4*K) - X)

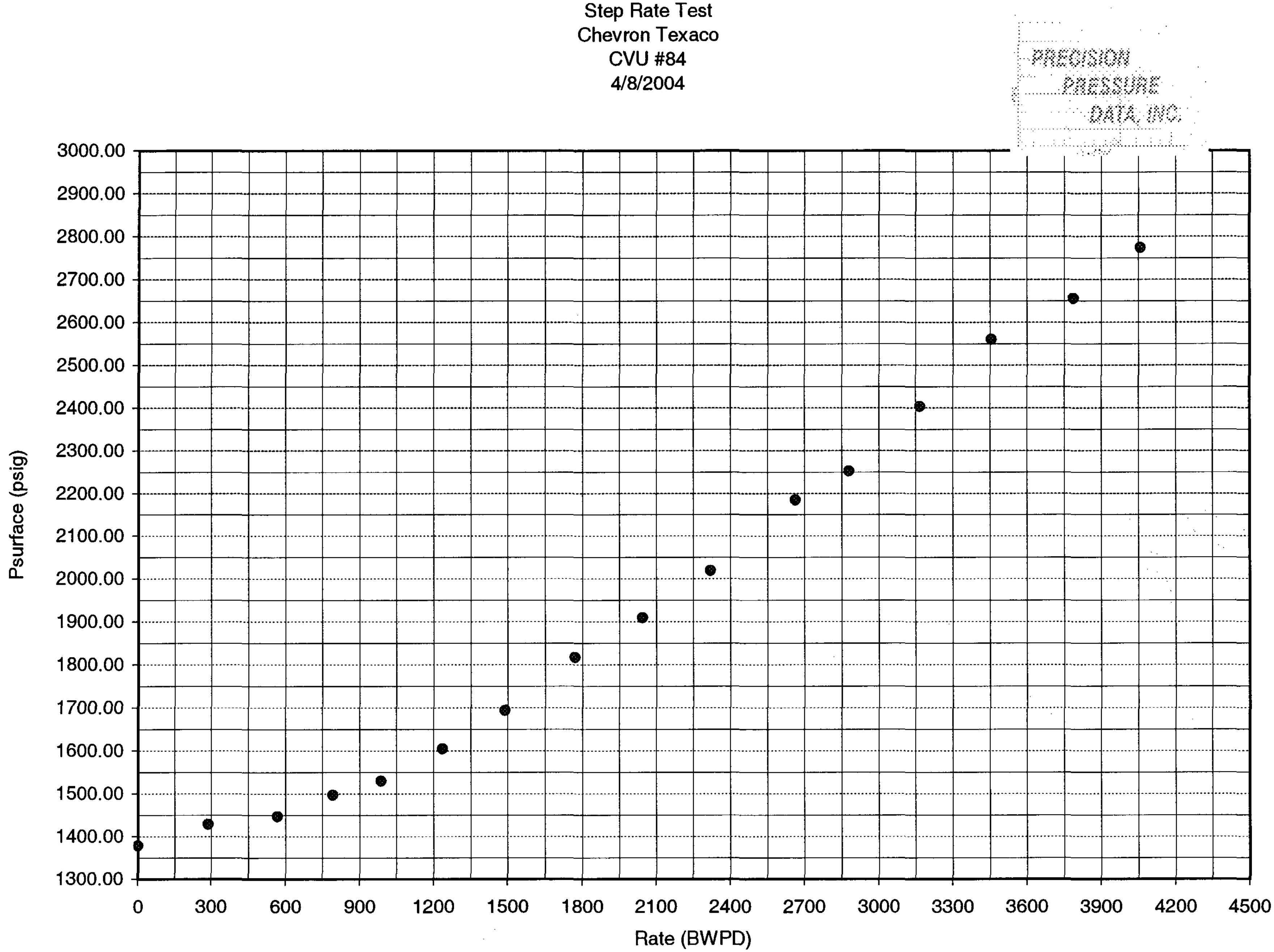
Total Ionic Strength= 1.5310
Solubility Constant, K= 0.00290
X= 0.0876

S= 51.25 me/l

Laboratory analysis shows that this water contains 3.33 me/l, therfore the tendency towards calcium sulfate deposition does not exist.


Step Rate Test
Chevron Texaco
CVU #84
4/08/2004
PRECISION PRESSURE DATA, INC.
BHP (psia)
4200.00
4100.00
4000.00
3900.00
3800.00
3700.00
3600.00
3500.00
3400.00
3300.00
0
300
600
900
1200
1500
1800
2100
2400
2700
3000
3300
3600
3900
4200
4500
Rate (BWPD)

Step Rate Test
Chevron Texaco
CVU #84
4/8/2004



Step Rate Test

CHEVRON TEXACO
CVU #84
TEST DATE 4/8/2004

Injection Rate (BWPD)	Psurface (psig)	B.H.P. (psia)	Psurface W/O FRICTION
0	1378.00	3302.50	1378.00
288	1428.00	3310.86	1425.00
569	1447.00	3331.80	1434.00
792	1497.00	3354.36	1473.00
987	1529.00	3375.00	1494.00
1238	1625.00	3416.50	1571.00
1490	1694.00	3453.30	1617.00
1771	1817.00	3489.90	1710.00
2044	1909.00	3545.30	1771.00
2319	2019.00	3595.30	1842.00
2664	2184.00	3657.90	1954.00
2880	2252.00	3704.40	1986.00
3168	2403.00	3770.60	2086.00
3519	2559.00	3841.66	2173.00
3787	2655.00	3913.30	2211.00
4060	2774.00	3995.70	2266.00

Run Depth: 4190 (above nipple)

Perforations: 4350-4682

Formation: Grayburg San Andres

Total Depth: 4800

Tubing Depth: 4268

Pkr. Depth: 4268

Tested By : J. Chesshir

Instrument #: 75794

TEST RESULTS

Test is Inconclusive

NEW MEXICO ENERGY, MINERALS
& NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION
2040 South Pacheco Street
Santa Fe, New Mexico 87505
(505) 827-7131

January 22, 1997

Texaco Exploration & Production, Inc.
P.O. Box 730
Hobbs, New Mexico 88241-0730

Attn: Mr. James Anderson

RE: Injection Pressure Increase,
Central Vacuum Unit Waterflood Project,
Lea County, New Mexico

Dear Mr. Anderson:

Reference is made to your request dated December 5, 1996 to increase the surface injection pressure on 15 wells in the above referenced waterflood project. This request is based on step rate tests conducted on the subject wells. The results of the tests have been reviewed by my staff and we feel an increase in injection pressure on these wells is justified at this time.

You are therefore authorized to increase the surface injection pressure on the following wells:

Well and Location	Maximum Surface Injection Pressure
Central Vacuum Unit Well No.26, Unit Letter J, Section 25, Twp. 17S, Rge. 34E	1500 PSIG
Central Vacuum Unit Well No.27, Unit Letter I, Section 25, Twp.17S, Rge. 34E	1500 PSIG
Central Vacuum Unit Well No.28, Unit Letter L, Section 30, Twp.17S, Rge. 35E	1550 PSIG
Central Vacuum Unit Well No.41, Unit Letter O, Section 25, Twp.17S, Rge.34E	1520 PSIG

Well and Location	Maximum Surface Injection Pressure	
Central Vacuum Unit Well No.42, Unit Letter P, Section 25, Twp. 17S, Rge. 34E	1450 PSIG	
Central Vacuum Unit Well No.43, Unit Letter M, Section 30, Twp. 17S, Rge. 35E	1500 PSIG	
Central Vacuum Unit Well No.55, Unit Letter D, Section 36, Twp. 17S, Rge. 34E	1500 PSIG	
Central Vacuum Unit Well No.57, Unit Letter A, Section 36, Twp. 17S, Rge. 34E	1530 PSIG	
Central Vacuum Unit Well No.58, Unit Letter D, Section 31, Twp. 17S, Rge. 35E	1500 PSIG	
Central Vacuum Unit Well No.71, Unit Letter G, Section 36, Twp. 17S, Rge. 34E	1500 PSIG	4/30/97 1850
Central Vacuum Unit Well No.74, Unit Letter E, Section 31, Twp. 17S, Rge. 35E	1500 PSIG	
Central Vacuum Unit Well No.84, Unit Letter M, Section 31, Twp. 17S, Rge. 35E	1450 PSIG	4/30/97 1850
Central Vacuum Unit Well No.93, Unit Letter M, Section 31, Twp. 17S, Rge. 35E	1400 PSIG	4/30/97 1750
Central Vacuum Unit Well No.94, Unit Letter N, Section 31, Twp. 17S, Rge. 35E	1550 PSIG	4/30/97 1850
Central Vacuum Unit Well No.138, Unit Letter P, Section 36, Twp. 17S, Rge. 34E	1550 PSIG	
All wells located in Lea County, New Mexico.		

The Division Director may rescind this injection pressure increase if it becomes apparent that the injected water is not being confined to the injection zone or is endangering any fresh water aquifers.

Sincerely,

William J. LeMay
Director

WJL/BES

cc: Oil Conservation Division - Hobbs
Files: Case File No.6008 (R-5530); PSI-X 2nd QTR 97