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Acoustic Foam Depression Tests

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ABSTRACT

A knowledge of the producing bottomhole pressure is desired in most artificial lift wells to determine if the well is being produced efficiently. An acoustic liquid level test and casing pressure measurement permits calculation of the PBHP. If the well contains liquid above the formation and the well produces gas from the casing annulus, the liquid column is aerated with gas bubbles. These bubbles are continuously moving upward through the gaseous liquid column. The gas is vented at the surface. The gradient of this gaseous liquid column is not known with a high degree of precision.

One technique for determining the gradient of the gaseous liquid column is to depress the liquid level by closing-in the casing valve. Stopping the flow of gas from the casing annulus at the surface of the well causes the casing pressure to increase. The casing pressure increase depresses the height of the gaseous liquid column. The test can be continued to determine the gas/liquid interface pressure as the top of the gaseous liquid column is depressed This data can be used to calculate the gradient of the gaseous liquid column and the producing bottomhole pressure.

Several wells were tested which contained bottomhole pressure sensors. The increase in producing bottomhole pressure was measured as the liquid from the casing annulus was displaced into the pump which necessarily reduces liquid flow from the formation. The casing pressure and top of the gaseous liquid column was also determined. Several examples are

presented to show the effect of closing-in the casing annulus gas vent valve on the producing bottomhole pressure, casing pressure and height of the gaseous liquid column.

INTRODUCTION

The determination of the bottomhole pressure in a producing well is important The producing bottomhole pressure should be low when compared to the reservoir pressure when the maximum production is desired. The producing bottomhole pressure (PBHP) and the static bottomhole pressure (SBHP) are used to determine the producing rate efficiency of the well. The PBHP and the SBHP are used in conjunction with the well test to determine the maximum production capability of the well. [1]

The PBHP can be determined by surface acoustic surveys without the need of lowering pressure gauges into the well in most cases. The PBHP is the summation of the casing pressure, gas column pressure and the pressure exerted by the liquid column if a liquid column exists above the pressure datum.

If the well does not produce gas from the casing annulus, the PBHP can be calculated accurately by summing the casing pressure, gas column pressure and the gas free liquid column pressure. The casing pressure should be measured accurately. The specific gravity of the gas in the casing annulus can be calculated from the measurement of acoustic velocity when an acoustic liquid level depth test is performed. This permits calculation of an accurate gas column pressure and a gas/liquid interface pressure. The gradient of the gas free liquid column can be determined accurately using various correlations or the referenced sources. [2,3]

However, the liquid column in most wells is aerated by free gas which is produced from the formation. The gas flows up through the liquid column and vents at the surface of the well into the flow line. Most often, the flow of gas into the wellbore and up through the liquid column is continuous. If the gas flow rate is small, the height of the liquid column is increased very little by the existence of gas bubbles in the liquid column. If the well produces a considerable amount of gas up the casing annulus, however, the liquid column may be aerated such that the height of the gasified column is more dun five times greater than would be the height of a gas-free liquid column.[4] In some cases, the casing annulus gas flow rate is so high that some of the liquid in the casing annulus is discharged at the surface of the well into the flow line.

The title of this paper is "Acoustic Foam Depression Tests." Many definitions exist for foam. One definition is a stabilized froth. Another definition is a light frothy mass of fine bubbles formed in or on the surface of a liquid. Sometimes the term foam is used when referring to the gas and liquid present in the casing annulus of a well which is producing gas at the surface. An excellent paper by Sheng, et al.,[10] discusses foamy oil stability. Foamy oil was created by reducing the pressure on a saturated oil. The reduction of pressure resulted in the liberation of small gas bubbles within the oil column and the small gas bubbles caused the oil column to rise. The foam dissipated within three hours in most tests in the study.

Please refer to Figure 1. Foam does not exist on top of a gas free liquid column as shown in Figure IA. Although a foam condition on top of a gas free oil column is sometimes described, the oil in the casing annulus is stable (as oil is observed to exist in a storage tank). Stable pressures in the oil column prevent the formation of bubbles within the oil column. Absence of free gas production from the reservoir prevents the formation of small gas bubbles from the fluid production. Thus, the accumulation of foam on top of a gas free liquid column cannot exist. Sometimes, the condition shown in Figure I B is described or shown. Free gas bubbles cannot be continuously liberated from the middle portion of the oil column because the pressure within the oil column cannot be continuously reduced (as described by Sheng, et al.[10]) Figure IC indicates the oil and gas distribution in a producing oil well which produces gas up the casing annulus. Free gas bubbles flow from the formation into the wellbore, and the gas bubbles migrate upward through the oil column. The gas collects above the top of the oil and is produced at the surface. The oil in the gaseous liquid column is saturated with gas and the gas saturation varies depending upon the pressure at the depth of the oil. In most cases, the liquid in the casing annulus remains in the casing annulus, and the gas is produced at the surface. In a few cases, both gas and oil (and sometimes water) flow from the casing annulus.

C.P. Walker [5,6] developed a process for determining the producing bottomhole pressure in wells which have gaseous liquid columns. The procedure consisted of determining the pressure at the gas/liquid interface at normal operating conditions. Then, the casing pressure was increased by use of a back-pressure valve and stabilized. When the liquid level was stable, the gas/liquid interface pressure was determined at the lower depth. The liquid level depths were plotted against the gas/liquid interface pressures. The pressures at the gas/liquid interfaces were extrapolated to the producing formation depth. Walker's studies and other studies[4] indicated that gaseous liquid columns have a constant gradient throughout the entire column. The data in this study shown in Table I was obtained by depressing the top of the gaseous liquid column without stabilizing the casing pressure and the top of the gaseous liquid column. This modified Walker procedure was used to determine the pressure at a downhole ESP pressure sensor.

Other acoustic techniques are available for determining downhole pressures below gaseous liquid columns. In general, the procedures conist of measuring the gas flow rate from the casing annulus and claculating the gradient of the gasified liquid column as a function of the gas flow rate. [4,7,8] The casing annulus gas flow rate can be determined from actual gas flow measurements at the surface. Or, the gas flow rate can be determined using the buildup in casing pressure when the casing valves are closed and the well continues to produce up the tubing.

The purpose of this work is to study the behavior of fluids which exist in the casing annulus of a producing well so that a more accurate PBHP can be obtained using acoustic techniques.[9]

SELECTION OF WELLS

Fourteen wells were tested by performing foam depression tests (ir gaseous liquid column depression tests). All of these wells but F217 contained downhole pressure sensors. The well depths were 5300 to 5700 feet (1600 to 1800 meters). All of the wells were in CO_2 flood projects. The ESP pumps were typically above the formation. The produced liquid volumes ranged from 1054 to 6,600 BPD (170 to 1050 m^3/D), and the casing annulus gas flow rates ranged from 0 to 1.1MMCF/D (0 to 30,000 m^3/D), The gaseous liquid column depression rates varied from 0 to 5000 ft. (1500 m) in 6 hours when the casing valves were closed. The total gas production from one well was 4.6MMCF/D (130,000 m^3/D but all of the gas was produced up the tubing and none up the casing annulus. The average API gravity of the oil was 34, and the water specific gravity was 1.02. The gas gravity varied from 0.7 to 1.5 depending upon the concentration of C02 in the produced gas.

TESTING PROCEDURE

The testing procedure consisted of first recording the ESP sensor pressure. Then, an acoustic computerized instrument and acoustic wellhead were connected to the well. The acoustic wellhead generated an acoustic pulse which traveled through the casing annulus gas and was reflected by the collars and the liquid level back to a microphone located in the acoustic wellhead. The electrical signal was digitized and stored in computer memory. The data was digitally filtered and processed to obtain the acoustic liquid level depth. The casing pressure was measured using an accurate pressure transducer. The system also acquired casing pressure data on a fifteen second interval so that the change in casing pressure could be recorded. The casing valves were closed immediately before the acoustic liquid level depth measurement to prevent gas flow from the casing annulus, but the ESP's continued to produce liquid up the tubing. The casing valves remained closed throughout the depression test. Most of the casing pressures at the beginning of the test were in the 50-150 PSI range but increased substantially in some wells.

Table I is a record of the tests performed. It includes the well description, elapsed time after the casing valves were closed, the casing pressure, the production rate, the liquid level depth, the gas/liquid interface pressure, and the ESP pressure sensor reading. An attempt was made to depress the top of the gaseous liquid column to within 100 feet of the ESP pressure sensor but time restrictions and other factors prevented depressing the top of the gaseous liquid column to the pressure sensor on most wells.

CARBON DIOXIDE CONSIDERATIONS

In most wells which produce hydrocarbon gas up the casing annulus, the gradient of the gaseous liquid column is uniform. Thus, when the top of the gaseous liquid column is depressed by increasing the casing pressure, a constant gradient is noted throughout the gaseous liquid column. See references 4, 5, 6 and 8. However, CO_2 gas behaves differently than a hydrocarbon gas. Please refer to Figure 2. The graph is a plot of the gradient of 35 API gravity oil and 0.85 specific gravity hydrocarbon gas as a function of pressure when the temperature is 100 F. The gradient of CO_2 is also plotted. The CO^2 gradient is similar to the hydrocarbon gas gradient below 600 PSI and to the oil gradient above 1600 PSI. Between these two pressures, the gradient changes from behaving as a gas to behaving as a liquid. This was noted on fluid depression tests on wells 5518 and 5520. Another interesting behavior of the $C0_2$ gas was noted on Well 5518 during tests N, 0 and P. The interface pressure was approximately 950 PSI. The gas/liquid interface was in a state where the gas phase and liquid phase were not distinctly separate. That is, a sharp boundary between the gas phase and liquid phase did not exist. Even though the casing pressure was very favorable for most acoustic liquid level testing, a distinct reflection from the gas/liquid interface was not obtained. Probably the change from gas phase to liquid phase occurred over several feet (a few meters) rather than being a distinct interface. Performing these tests on wells which produce $C0_2$ complicated the analysis of the data somewhat but a selection of other wells having BHP sensors which produced hydrocarbon gas only was not available.

CASING ANNULUS LIQUID DEPRESSION CAUSED BY AN INCREASE IN CASING PRESSURE

If the casing valves are closed during normal operation and the formation produces free gas, the free gas will accumulate in the casing annulus and will eventually depress the top of the gaseous liquid column to the pump inlet if the pump is functional. This occurs in all wells which produce free gas from the formation and do not vent gas from the casing annulus.

In some wells, a liquid column may form above the formation which results in a producing bottomhole pressure that restricts flow from the formation to match the capacity of the pumping system. If the PBHP and pump intake pressure (PIP) are above bubble point pressure, free gas bubbles will not be present in the liquid column. Wells 5601, F217 and 117B do not have free gas bubbles in the casing annulus liquid.

In most wells, free gas is produced from the formation and vented at the surface from the casing annulus into the flow line. Oftentimes. the pump does not produce all of the liquid from the wellbore and a liquid column forms above the pump. If gas flows from the formation up the casing annulus and vents at the surface, the flow of gas will aerate the liquid column and cause the height of the liquid column above the pump to increase. At extremely high gas flow rates, the liquid in the casing annulus may be lifted to the surface and produced from the well as observed in Wells 5518 and 5520. In some situations, oil and water in the casing annulus will be lifted to the surface and will be produced out of the casing annulus.

In a well having liquid above the formation and having gas vented at the surface, a gaseous liquid depression test can be performed by closing in the casing annulus valves while tile well continues to produce up the tubing. Closing the valves will prevent gas flow from the casing annulus and result in casing pressure buildup. This will result in an increase in pressure at the top of the gasified liquid column. As the gas/liquid interface pressure increases, the top of the gasified liquid column will be depressed. The gasified liquid column depression rate is given by:

$$R = \frac{dP}{dT} \times \frac{1}{G_{GL}}$$

See nomenclature ... 1

The rate of depression of the gasified liquid column on a per-day basis is:

$$R = \frac{dP}{dT} \times \frac{1440}{G_{GL}} \qquad \text{... 2}$$

Table 2 is the capacity in barrels per foot (or m^3/m) in the casing annulus of various combinations of casing and tubing. Multiplying the rate in Equation 2 by the capacity results in Equation 3 which is the rate in barrels per day (or m^3/D) at which the volume of gasified liquid column is displaced downward.

$$V = \frac{dP}{dT} \times \frac{1440}{G_{GL}} \times CAP \qquad \text{... 3}$$

Let F be the fraction of oil in the gasified liquid column so that

$$F = \frac{G_{GL}}{G_L}$$

The rate of oil displacement in barrels per day (or m^3/D), down the casing annulus can be expressed by:

$$V = \frac{dP}{dT} \times \frac{1440}{G_{GL}} \times CAP \times F \qquad \text{... 4}$$

or,

$$V = \frac{dP}{dT} \times \frac{1440}{G_{G}} \times CAP \qquad \text{... 5}$$

When the casing valves are closed and the casing pressure increases, liquid from the casing annulus above the pump is displaced into the pump at approximately the rate shown by the equation above. If the pump capacity remains almost constant, then, when liquid is displaced from the casing annulus into the pump, necessarily less liquid will flow from the formation into the well. This will result in an increase in the producing bottomhole pressure.

EFFECT OF LIQUID DEPRESSION ON THE PRODUCING BOTTOMHOLE PRESSURE

The rate at which liquid is displaced from the casing annulus into the pump is given in the previous Equation No. 5. This will necessarily reduce the flow of liquid from the formation into the wellbore and cause an increase in the producing bottomhole pressure. Using a linear inflow performance relationship, the productivity index remains constant. That is, the formation production rate divided by the draw-down pressure is a constant. If the production rate from the formation is reduced, a corresponding reduction in draw-down pressure will occur. The following equation is an expression of the change in the draw-down pressure to be expected when the casing valves are closed.

Change in draw-down pressure, percentage, dimensionless

$$P_{DD} = \frac{dP}{dT} \times \frac{1440}{G_L} \times CAP \times 100 \qquad \ldots 6$$

Applying Equation 6 to Well 5529 calculates that the producing bottomhole pressure would increase approximately 1% during the test period due to depressing liquid from the casing annulus into the pump. Note that the pressure sensor changed very little during the test. Applying Equation 6 to Well 5520 indicates that the producing bottomhole pressure would increase approximately 11%. The ESP pressure sensor increased more than 11%. However, Equation 6 does not account for the liquid that was being produced from the casing annulus of the well which would also affect the producing bottomhole pressure when the casing valves were closed. Ina more typical lower volume well, the buildup in casing pressure will have a more dramatic affect. For example, assume a well which produces 80 BPD (13 m^3/D) and has 2-3/8" tubing with 5-1/2" casing and a casing pressure buildup rate of 0.5 PSI/M (3 kPa/M). The draw-down pressure would be decreased by 50% during an extended depression test.

ESP SENSOR READINGS VS. WIRELINE PRESSURE GAUGE MEASUREMENTS

Table 3 shows data on ESP sensor readings versus wireline pressure gauge measurements at shut-in conditions. Three of the ESP sensors are in close agreement with the wireline gauge measurements. However, Well 5510 had an ESP sensor reading of 1119 PSI while the wireline gauge measurement was s 2006 PSI. The other wells were not tested with the wireline gauges. This shows that the accuracy of ESP sensors should be checked by acoustic surveys periodically.[8]

ANALYSIS OF THE ACOUSTIC FOAM DEPRESSION TESTS

All of the wells in these tests produced large volumes of liquid. When the casing pressure buildup rate was less than 0.8 PSI per minute (5 kPa/M), the liquid depression rate from the casing annulus into the pump resulted in negligible change in the liquid rate produced from the formation and hence a change in the producing bottomhole pressure was not noted. The pressures at the top of the gaseous liquid columns were extrapolated to the sensor depth. Very good agreement existed between the modified Walker procedure and the ESP sensor pressures on Wells 4314, 5507, 5510, 5523, 5527 and 5529. Please refer to Figures 3, 4, 5, 6, 7 and 8. On well 5515 (Figure 9), the extrapolation of the gas/liquid interface pressure was 98 PSI less than the sensor pressure. Had the test been extended, probably the trend of the pressures at the top of gas/liquid interface would have continued which would have indicated that the ESP sensor pressure was in excess of the actual pump intake pressure. It appears that the ESP sensor pressure is approximately 100 PSI (700 kPa) high.

Wells 5518 and 5520 measured high casing pressure buildup rates. These wells were flowing liquid (probably oil and water) from the casing annulus. The volumes of liquid flow from the casing annulus were not known. This liquid flow from the casing annulus stopped when the casing valves were closed. Also, when the casing valves were closed, liquid was displaced downward into the pump due to the increase in casing pressure. This resulted in reduced pump capacity for produced liquids from the formation. The depression of liquid from the casing annulus and the stoppage of flow from the casing annulus caused an increase in the producing bottomhole pressure. Please refer to Figures 10 and 11. Note that the gradient of the gaseous column appears to change as the pressure increases above approximately 500 PSI. This is probably due to the behavior of the $C0_2$ gas. Considerable CO_2 gas was present in the casing annulus which was determined from the acoustic velocity measurement. Also note that the final gas/liquid interface pressure on Well 5520 was close to the sensor pressure. Fluid depression tests should be carefully analyzed to determine that the liquid depression rate from the casing annulus into the pump will not cause a significant change in the producing bottomhole pressure (or draw-down pressure) which would cause the extrapolation of the pressures at the top of the gasified liquid column to be in excess of the normal producing bottomhole pressure.

Well 5503 had a very slow casing pressure buildup rate. Two to three weeks would have been required to depress the top of the gaseous liquid column to the pump sensor. When a very slow casing pressure buildup rate exists, the gradient is assumed to be 100% liquid and the gradient of the liquid column can be determined from Reference 2. The casing pressure buildup rate was very slow on Well 5512. The liquid above the pump is assumed to be gas free oil which would have a gradient of approximately 0.34 PSI/ft. as given in Reference 2. This would calculate a bottomhole pressure of 698 PSI (4809 kPa) which was in very good agreement with the sensor pressure of 664 PSI(4578 kPa)

The following three wells did not produce gas up the casing annulus. Well 5601 had a casing pressure less than the flowline pressure which indicated that free gas bubbles did not exist in the liquid column. Using a gradient for the liquid column given from Reference 2, the calculated bottomhole pressure would be 1279 PSI (8817 kPa) The ESP sensor pressure was 1522 PSI(10492 kPa). Well F217 did not produce gas from the casing annulus. This well produced 608 BOPD (97 m^3/D) and 5977 BWPD (950 m^3/D) up the tubing. The gas production up the tubing was high at 4569 MCF/day (13,000m^3/D). Note that the producing bottomhole pressure and pump intake pressure of approximately 1596 PSI (11,000 kPa) are above the bubble point pressure of the miscible phase, and free gas is not produced up the casing annulus. All of the fluid is produced through the pump and up the tubing. The pump inlet is not exposed to free gas bubbles. Well I17B had the producing bottomhole pressure and pump intake pressure in excess of bubble point pressure. Free gas does not exist in the liquid column. The calculated bottomhole pressure from acoustic techniques is 270 PSI (1860 kPa) which compares favorably with the sensor pressure of 208 PSI (1433 kPa)

CONCLUSIONS AND SUMMARY

The modified Walker method of obtaining downhole pressures by extrapolating the pressures at the top of gaseous liquid columns which have been depressed by increasing the casing pressure is a good procedure for obtaining downhole pressures in many cases.

Care should be used during the depression of the gaseous liquid column to ensure that the depression of the liquid from the casing annulus into the pump does not substantially increase the producing bottomhole pressure. In cases where the PBHP is substantially changed during the depression test, the top of the gaseous liquid column should be stabilized near the pressure datum by use of a back-pressure valve on the casing annulus. Use Equation 6 to determine when the draw-down pressure will be substantially decreased during the depression test and a back-pressure valve should be used to stabilize the casing pressure and top of the gaseous liquid column.

The top of the gaseous liquid column should be depressed close to the pressure datum for more accurate bottomhole pressure determinations since the pressure at the top of the gas/liquid interface can be determined accurately.

As indicated by the comparison of ESP pressure sensor readings to wireline pressure gauge measurements, acoustic gaseous liquid column depression tests should be performed periodically to verify the accuracy of ESP pressure sensors.

When the produced gas in the casing annulus contains a high percentage of CO_2 the gaseous liquid column depression test should be continued until the gas/liquid interface is near the pump, This will result in more accurate downhole pressure determination.

NOMENCLATURE

dP = change in casing pressure
PSI (kPa)

dT = time of casing pressure test, min.

G_{GL} = gradient of gaseous liquid column,
PSI/ft. (kPa/m)

G_L = gradient of gas free liquid column,
PSI/ft. (kPa/m)

CAP = capacity of casing annulus,
Bbl/ft. m^3/m

Q = production rate of well, total liquid,
BPD m^3/day

P_{DD} = change in draw-down pressure,
percentage, dimensionless

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Table 1- Summary of all Liquid Level Depresssion Tests

Well Number	Test ID	Elapsed Time in Minutes	Well Test BOPD-BWPD-MCFPD	Casinghead Pressure, psi	Depth to Fluid Level, ft.	Computed Pressure at Gas/Liquid Interface, psi	Modified Walker Extrapolated BHP, psi	Pump Intake Pressure Sensor Reading, psi
4314	A	0	32-1290-13	116.2	4581	135	307	308
4314	B	480		152	4675	177		309
4314	C	1109		194.7	4845	226		309
4314	D	1648		228	4965	267		307
5503	A	0	170-1297-0	106.8	2090	117	N/A	1196
5503	B	6		106.8	2094	117		815
5503	C	435		141.1	2125	155		1197
5503	D	1241		144.2	2059	158		1198
5507	A	0	4-1710-220	136.9	3159	158	858	886
5507	B	11		139	3178	161		885
5507	C	469		205.5	3381	241		885
5507	D	1049		270.2	3570	320		885
5507	E	1580		307.5	3705	366		887
5510	A	0	26-1304-193	127.7	3587	151	528	519
5510	B	17		133.8	3594	158		513
5510	C	67		150.3	3709	179		462
5510	D	76		154.2	3693	184		464
5510	E	484		279.7	4352	359		451
5512	A	0	7-1629-9	118.1	3312	132	950	664
5512	B	30		119.4	3316	133		664
5512	C	570		128.9	3343	143		666
5512	D	1198		142.8	3372	159		666
5512	E	1804		154.7	3394	172		661
5515	A	0	3-1051-11	109.2	4521	131	349	441
5515	B	13		110.5	4531	133		441
5515	M	247		142	4642	171		443
5515	N	251		142.6	4650	171		441
5515	O	312		143.6	4648	173		443
5515	P	839		204.9	4915	248		441
5518	A	0	32-1290-13	212.2	36	212	921	928
5518	B	5		260.2	764	271		967
5518	C	10		295.1	1106	313		1007
5518	D	15		328.2	1416	353		1023
5518	E	20		355.3	1668	388		1026
5518	F	25		380.7	1834	419		1058
5518	G	35		424.5	2032	474		1074
5518	H	45		465	2162	524		1102
5518	J	56		501.6	2271	569		1101
5518	K	66		535.6	2357	611		1121
5518	L	84		588	2641	685		1150
5518	M	106		640	3022	766		1181
5518	N	250		768.4	3325	867		1222
5518	O	254		769.9				1222
5518	P	256		769	3108	947		1233
5520	A	0	13-1386-888	257.7	34	258	922	777
5520	B	5		293.7	843	306		815
5520	C	53		446.8	1434	480		815
5520	D	57		457.6	1513	494		853
5520	E	62		470.3	1593	510		853

Table 1- Summary of all Liquid Level Depresssion Tests

Well Number	Test ID	Elapsed Time in Minutes	Well Test BOPD BWPD-MCFPD	Casinghead Pressure, psi	Depth to Fluid Level, ft.	Computed Pressure at Gas/Liquid Interface, psi	Modified Walker Extrapolated BHP, psi	Pump Intake Pressure Sensor Reading, psi
5520	F	68		484.2	1655	527		853
5520	H	90		527.1	1891	582		853
5520	I	95		537.3	1979	595		891
5520	J	104		551.6	2166	617		892
5520	K	117		572	2543	655		892
5520	L	134		594.2	3019	700		930
5520	M	141		602.8	3260	718		930
5520	N	180		640.5	4495	825		930
5520	O	185		644.6	4650	839		930
5520	P	334		683	5209	925		987
5523	A	0	67-2080-369	116.6	1116	122	1123	1308
5523	B	10		123.5	1164	130		1308
5523	C	475		233	1768	249		1311
5523	D	1287		382	2265	418		1309
5523	E	1612		432.2	2459	476		1308
5527	A	0	34-1529-24	100	3666	115	507	614
5527	B	465		157.3	3968	182		584
5527	C	1031		238.7	4260	278		569
5527	D	1040		248.3	4321	280		569
5527	D	1645		325.1	4685	384		544
5529	A	0	63-2070-187	101.5	2551	113	936	882
5529	B	415		235.3	3030	266		882
5529	C	1182		384.7	3564	443		883
5529	D	1557		455.2	3818	530		884
5601	A	0	22-2179-6	46.9	1534	51		1522
5601	B	20		41.4	1532	45		1523
F217	A	0	608-5977-4569	85.6	1609	1596		
I178	A	0	183-1045-37	142.7	5951	178		208

Table 2 Casing Annulus Capacity

Casing Size,	Tubing Size,	Capacity	
in	in	Bbl/ft	m^3/m
4 1/2	2 3/8	0.011	0.006
5 1/2	2 3/8	0.019	0.010
	2 7/8	0.016	0.008
7	2 3/8	0.036	0.019
	2 7/8	0.033	0.017
	3 1/2	0.030	0.016

Table 3 - ESP Pressure Sensor vs. Wireline Pressure Gauge Measurements

Well Number	ESP Sensor Pressure, psi	Wireline Gauge Pressure, psi
5503	3186	3296
5510	1199	2006
5523	2612	2731
5601	2287	2267

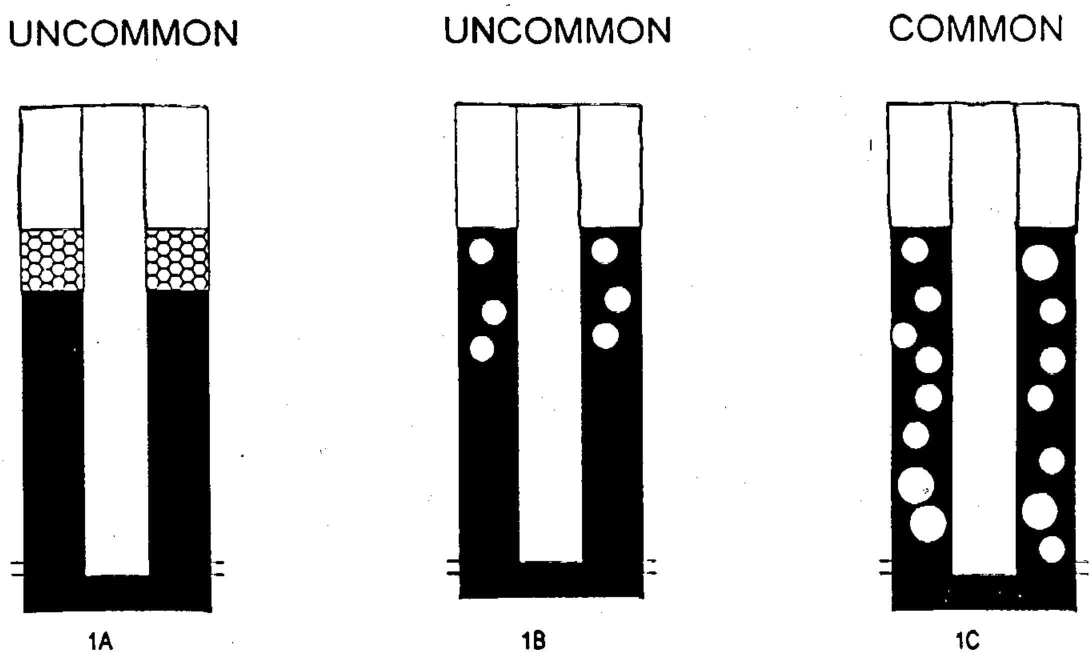

FIGURE 1 CASING ANNULUS FLUIDS

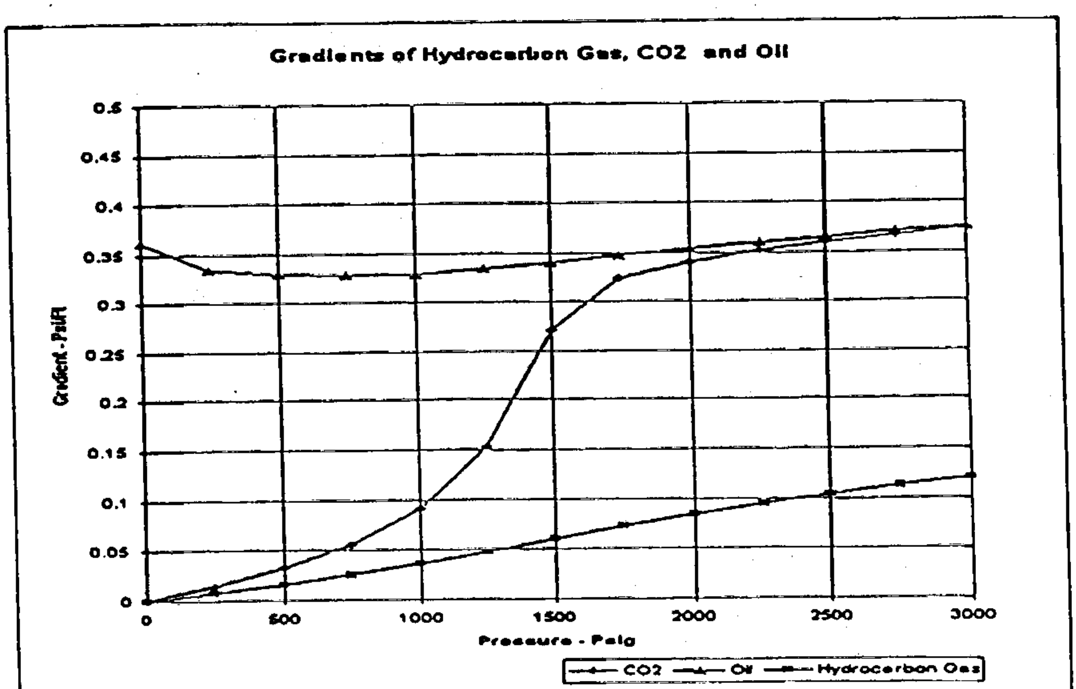

Figure 2

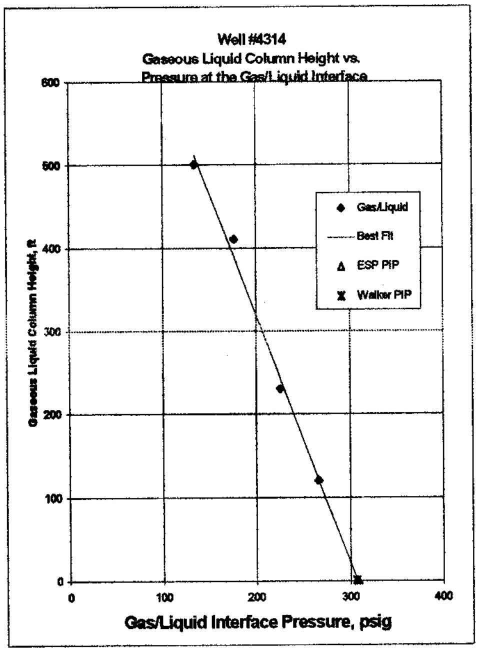

Figure 3

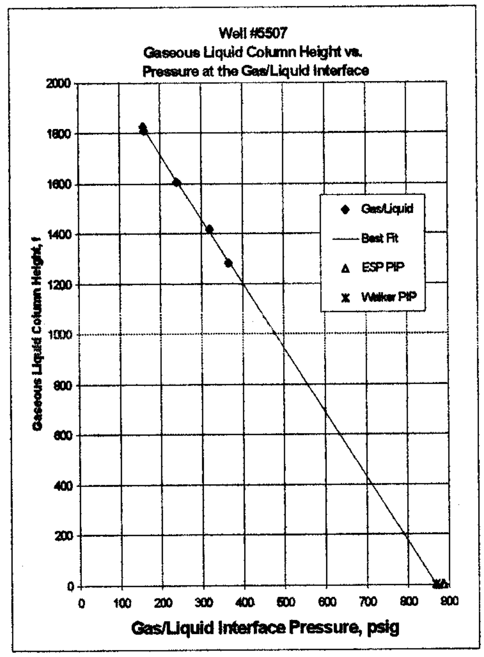

Figure 4

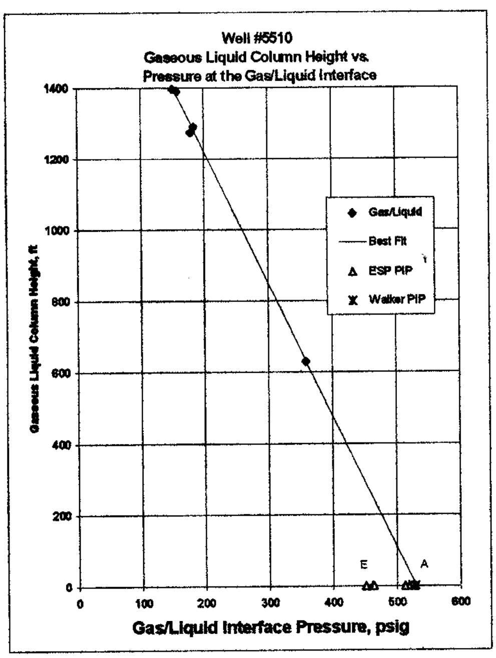

Figure 5

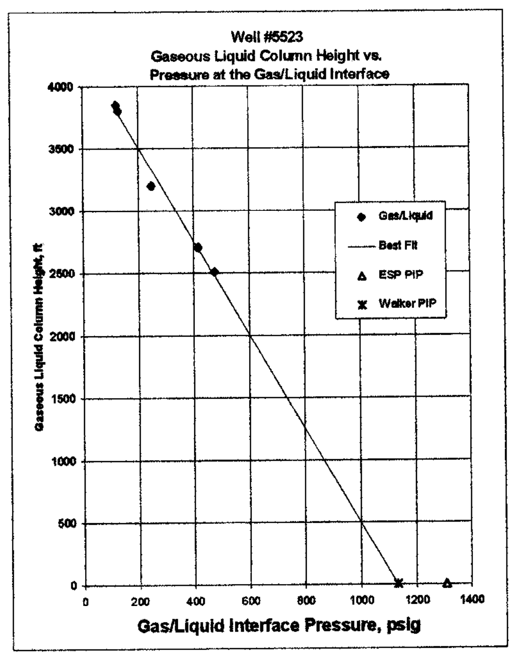

Figure 6

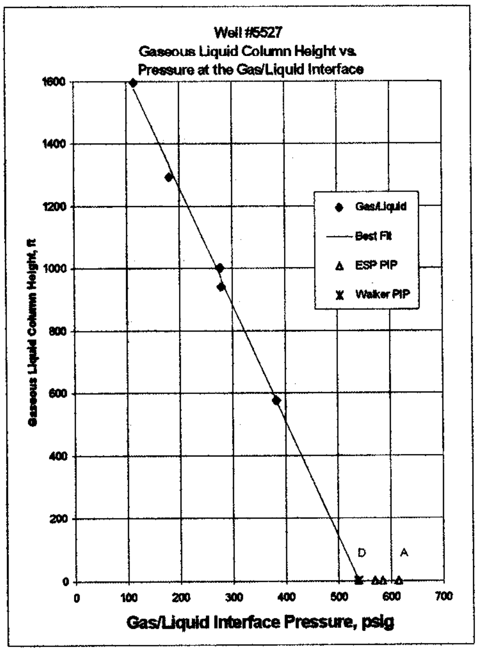

Figure 7

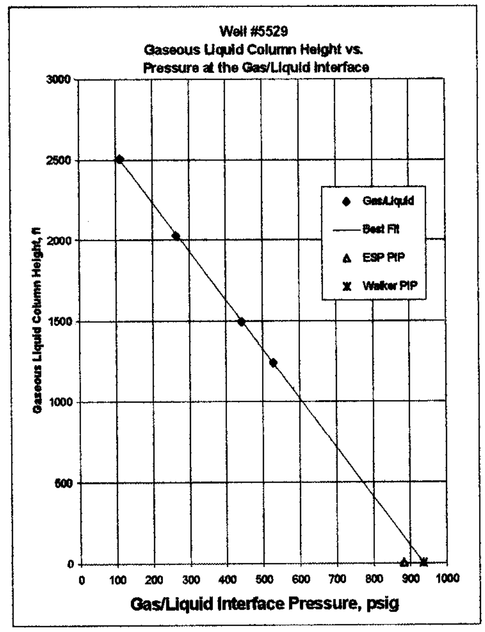

Figure 8

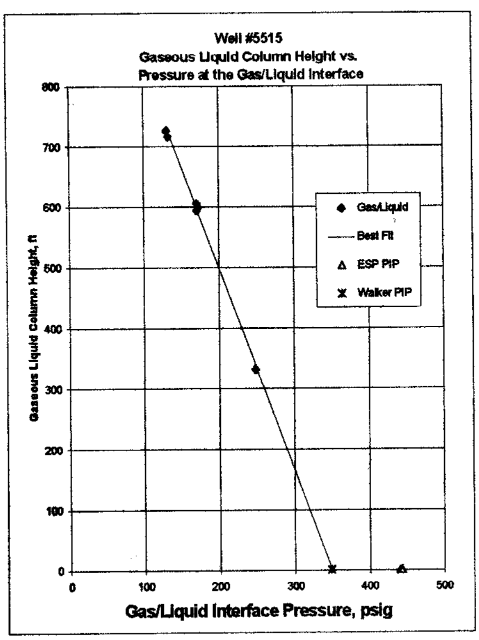

Figure 9

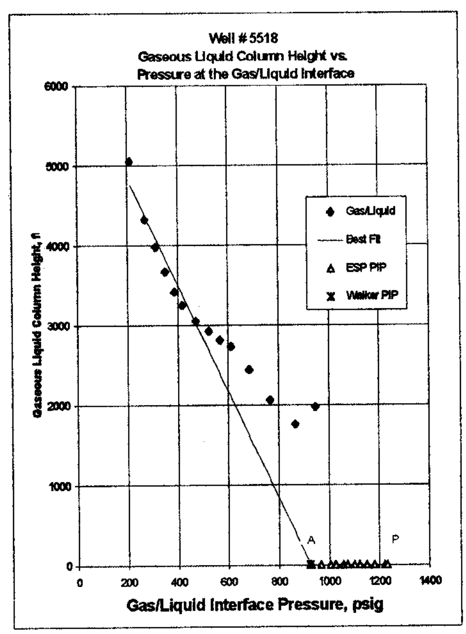

Figure 10

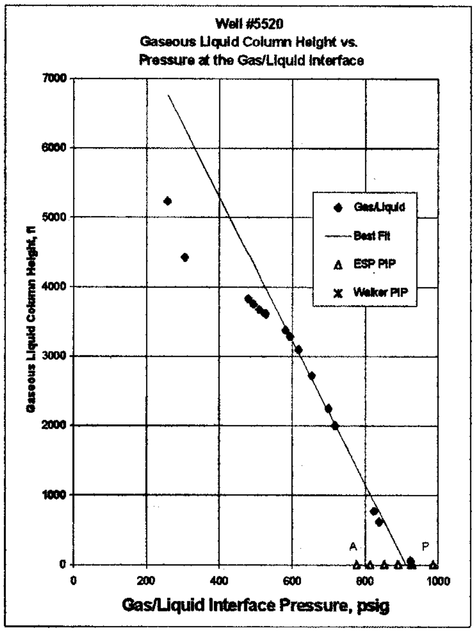
Well #5520
Gaseous Liquid Column Height vs.
Pressure at the Gas/Liquid Interface
7000
6000
5000
4000
3000
2000
1000
0
0
200
400
600
800
1000
Gaseous Liquid Column Height, ft
Gas/Liquid Interface Pressure, psig
Gas/Liquid
Best Fit
ESP PIP
Walker PIP
A
P

Figure 11