ACOUSTIC BOTTOMHOLE PRESSURES IN OIL, GAS AND CO_2 WELLS

James N. McCoy, Echometer Company
Augusto L. Podio, The University of Texas at Austin
Keneth Huddleston, Echometer Company

ABSTRACT

Acoustic instruments have been used routinely for many years as an aid in analyzing well performance of normal-pressure oil producers.[1]

Recent developments in equipment and techniques now permit more-accurate calculations of acoustic static bottomhole pressures at surface pressures up to 15,000 psi in corrosive (CO_2 and H_2S) environments. Equations and charts are presented herein for determining static bottomhole pressures from acoustic and well data. Also, a special technique is recommended for shutting-in a well which in most cases will yield more-accurate results.

The bottomhole pressure of wells producing high concentrations of CO_2 gas can be determined from acoustic data and the tables and figures given herein.

This method has been programmed for an inexpensive, portable notebook-size computer which can be used in the field to easily perform these calculations.

INTRODUCTION

The liquid level in a well may be determined acoustically by generating a pressure pulse at the surface and recording the echos from collars, obstructions, and liquid level.

A blank cartridge was the conventional source of pressure pulse until development of the modern gas gun. On wells having less than 100 psi, the gas gun volume chamber is pressurized to approximately 100 psi in excess of well pressure. The gas is then rapidly released into the well to create the pressure pulse. On wells having pressures in excess of 100 psi, the volume chamber in the gas gun is bled to a pressure less than the well pressure. Then, a valve is rapidly opened to permit wellhead pressure to expand into the volume chamber and create a rarefaction pressure wave.

A microphone converts the pressure pulses reflected by collars, liquid, and other obstructions (or changes in area) into electrical signals which are amplified, filtered, and recorded on a strip chart (Fig. 1). The liquid level depth can be determined by counting the number of tubing collars to the liquid-level reflection.

Changes in cross-sectional area are also recorded. When these changes are known, they can be used as depth references to determine liquid-level depth. Also, the distance to the liquid level can be calculated by travel time from the acoustic chart and acoustic-velocity data. Acoustic measurements were generally obtained by "shooting" down the casing/tubing annulus in packerless completions (Fig. 1).

However, equipment has been recently developed for shooting down the inside of close-makeup (flush) tubing at high pressures.

In most of the deeper, high-pressure gas wells, the casing/tubing annulus is isolated from the production string by a packer. Thus, a static bottomhole pressure must be obtained by shooting down the inside of the tubing.

Weeks[2] discusses a high-pressure gas gun (Fig. 2) which will operate up to 15,000 psi and can be operated through needle valves already installed on the well. This gun utilizes gas in the well to generate the initial pressure pulse. Neither an external gas supply nor a "blank" is necessary and the gun is suitable for wells having high concentrations of H_2S and CO_2.

PRESSURE DETERMINATION

The static bottomhole pressure is the sum of surface pressure, gas column pressure, and liquid column pressure. The accuracy of each of these pressures determines the accuracy of the static bottomhole pressure.

The principal uncertainty in the calculated bottomhole pressure generally arises from errors in the determination of the liquid column pressure. Such errors can be minimized by a shut-in procedure suggested herein.

The surface casing pressure can be measured with a calibrated pressure gauge or more accurately with a dead-weight tester. In most cases, the casing pressure is a high percentage of the static bottomhole pressure and an accurate measurement is desired.

The pressure due to a gas column is usually determined by equations, charts and tables using gas gravity and/or gas composition, temperature gradients, surface pressure, and depth. Techniques are offered herein for determining the gas column pressure in most wells.

Liquid column gradients are given herein with corrections for dissolved gas, pressure, and temperature.

A comprehensive manual published by the Canadian Energy Resources Conservation Board[3] also presents useful information for determining downhole pressures.

Podio[4] discusses a small portable computer to determine bottomhole pressures even in deep, high-temperature, high-pressure wells. The computer and software also calculate the gas column pressure in wells which contain non-hydrocarbon gases.

TUBING NEAR CASING PERFORATIONS

In a conventional oil well, the tubing intake is located near the casing perforations. When such a producing oil well (liquid level at the tubing intake) is shut-in, the liquid fill-up in the casing annulus will be the same ratio of oil and water that is normally produced by the well (Fig. 3).

If a producing oil well has liquid above the pump before being shut-in, the liquid above the pump in the casing annulus is oil. If gas is bubbling through the oil, the actual amount of oil present in the gaseous column can be determined by techniques discussed by Swaim & Gipson[5] or McCoy[6]. If the casing and tubing of this producing well are shut-in, additional liquid will often flow into the casing annulus. This additional liquid will also be the same ratio of oil and water that is produced by the well. The total oil at static conditions will be the amount of oil originally present in the casing annulus, plus the amount of oil that flowed into the wellbore after shut-in. The remainder of the liquid column will be water (Fig. 3A).

Annulus Gas

A special shut-in procedure is recommended for wells producing gas up the casing annulus to improve the accuracy by maximizing the casing pressure and minimizing the liquid column length.

1. Close the casing valves and continue to pump the well.

2. The casing pressure will increase and generally stabilize.

3. Shut-down the well and close the tubing valve until the casing pressure and liquid stabilize.

4. Then, run the acoustic survey.

During casing pressure buildup, the producing bottomhole pressure will increase as gas flow from the casing annulus is stopped. The increase in casing pressure depresses casing annulus liquid into the pump, reduces the pump capacity to formation fluids, and results in a higher producing bottomhole pressure. The liquid level will be depressed to the pump.

Note, in a producing well which has gas and liquid flowing into the wellbore, the liquid level is at the tubing perforations when the well is produced with the casing valves closed, i.e., gas collects in the casing annulus and depresses the liquid level to the tubing perforations.

Often, liquid does not flow into the wellbore after shut-down (see Brownscombe[8] and Stegmeir[9]). Thus, the static bottomhole pressure is simply the sum of casing pressure and gas column pressure (if no liquid is above the casing perforations). If liquid buildup occurs, the ratio of oil and water present in the liquid column will be the same ratio that is normally produced by the well (Fig. 4).

An SBHP Calculation Sheet is enclosed to facilitate calculating acoustic bottomhole pressures in wells which have the tubing intake near the casing perforations and have the liquid level at the tubing intake when the well is shut-down.

TUBING ABOVE CASING PERFORATIONS

In a producing well which has the tubing intake located a considerable distance above the casing perforations, a column of liquid exists in the casing that is approximately the same ratio of oil and water as that produced by the well.

When such a well (liquid level at the tubing intake) is shut-in, a fill-up of liquid will generally occur which is also the same ratio of oil and water that is produced by the well. The oil originally in the casing and the oil in the after-flow will migrate to the top of the liquid column. This oil will be in the casing annulus unless the oil volume exceeds the capacity of the casing annulus above the tubing intake. In that case, the oil column will extend down into the casing. Water will be below the oil to total depth (Fig. 5).

If liquid exists above a high pump intake in a producing well, the liquid will be oil. If gas is vented at the surface, the column will be gaseous. When this well is shut-down, the after-flow will also be the same ratio of oil and water that is produced by the well. Thus, the total oil will be the original oil in the casing annulus above the tubing intake, plus the oil in the casing between the tubing intake and the casing perforations, plus the oil in the after-flow. This oil column will exist in the casing annulus and may extend below the bottom of the tubing into the casing. Water will be below the oil (Fig. 5A).

Annulus Gas Vented

If the well is venting gas up the casing annulus, a shut-in procedure is recommended.

1. Close the casing valve and allow the casing pressure to increase until stabilized. If a gaseous oil column existed above the pump, the oil will be depressed to the tubing intake.

2. After the increased casing pressure has stabilized, shut-down the well. Observe the casing pressure to determine when static conditions are obtained.

Determine the total volume of liquid that is present in the casing annulus above the pump and the volume that is present in the casing between the formation and the pump. Multiply the total volume of liquid by the ratio of oil to total liquid (from well test) to determine the amount of oil in the well.

Determine the height of the oil column in the casing annulus. Oil may extend below the tubing into the casing. The remainder of the liquid column will be water.

Annulus Not Vented

If gas is not vented from the casing and a liquid column does not exist above the pump, shut-down the well. Monitor the casing pressure and/or liquid level to determine when the fluids have stabilized. Determine the total volume of liquid present in the casing and casing annulus. The amount of oil present in the well is equal to the total volume of liquid multiplied by the ratio of oil to total liquid produced by the well. The oil will exist in the casing annulus and possibly extend below the tubing intake into the casing. The remainder of the liquid below the oil will be water.

If the well does not vent gas and liquid is present above the tubing intake, the liquid above the tubing intake will be oil without gas bubbles. The casing (between the casing perforations and the tubing intake when the well is producing) contains water and oil in approximately the same ratio that is produced by the well. Determine the volume of oil present in the casing at producing condition. When the well is shut-down, additional liquid will flow into the well. Determine the volume of liquid flow into the well after shut-down. Determine the amount of oil present in the after-flow by multiplying the after-flow volume by the ratio of oil to total liquid. Determine the total volume of oil in the well by adding (1) the original oil above the tubing intake (casing annulus), (2) oil that was present in the casing between the tubing intake and the casing perforations, and (3) the oil in the after-flow. The oil will be located in the casing annulus unless the oil extends below the tubing into the casing. Water will extend from the oil to the casing perforations.

LIQUID COLUMN PRESSURE

The pressure gradient of oil may be determined from Table 1 or Fig. 6. Fig. 6 should be used to compensate for dissolved gas and the effect of higher temperatures. The "liquid pressure" term in Fig. 6 is the average oil column pressure.

The specific gravity of produced water can be determined by hydrometer. The water gradient is 0.433 psi/ft. x specific gravity x correction factor. The correction factors for temperature, dissolved gas, and pressure are given (Fig. 7).

GAS COLUMN PRESSURE

The gas column pressure of a hydrocarbon gas as a function of specific gravity, surface pressure and depth is given in Fig. 8. Assumed conditions are a surface temperature of 60°F and a gradient of 0.015°F/ft. Fig. 8 can be used with good accuracy for most cases unless pressure or depth limitations are exceeded, temperature conditions are abnormal, or non-hydrocarbon gases exist.

The gas column pressure can be determined by the following equation also:

$$P_{gc} = \frac{0.0188\ (P)\ (sg)\ (L)}{ZT}$$

where:

P_{gc} = pressure due to gas column, psi

P = average gas column pressure, psia

sg = specific gravity of gas (Air = 1.0)

Z = compressibility factor

L = length of gas column, ft.

T = average gas temperature, °R. (°F. + 460)

Below 300 psi, assume Z to be 1. From 300 to 2,000 psi, use Fig. 9. Above 2,000 psi, use the Z factor correlation by Katz, et al[11]. See Figs. 10 and 11. Refer to the example problem shown with the figures.

The pressure term and compressibility factor in the above equation should be at the mid-point depth of the gas column. The approximate pressure at the mid-point can be obtained by using Fig. 8 if depth and pressure limits are not exceeded. If Fig. 8 cannot be used, use the casing pressure and Z factor at surface pressure and average gas temperature. Calculate an approximate gas column pressure. Determine the mid-point pressure and then a new Z factor. Calculate a new gas column pressure. Iterate until the desired accuracy is obtained. In deep wells having a high bottomhole temperature and high gas gravity, the column should be divided into sections. See Bender and Holden[13]. The gas gradient can decrease considerably downhole. The computer divides the gas column into sections. However, the difference is negligible except in deep, high temperature, high gravity wells.

If the specific gravity of the gas column is not known, the specific gravity is related to acoustic velocity. Fig. 12 presents the specific gravity as a function of acoustic velocity for hydrocarbon gases at 75°F and pressures below 1,000 psi. Fig. 13 gives the specific gravity at 75°F and pressures above 1,000 psi.

The acoustic velocity should be determined near the top of the acoustic chart at a depth environment of 75°F. With the 11 point dividers set on the collar "kicks", determine the number of collar "kicks" per second. The acoustic velocity is obtained by multiplying the number of collars per second by the average joint length and then multiply by 2 (round trip travel time). Enter acoustic velocity (Figs. 12 or 13) and proceed horizontally to the pressure. The specific gravity of the gas is indicated below.

Settling of gas due to gravity has been observed from acoustic velocity data in many wells. Gas specific gravity measured at the surface using a gas gravity meter may not yield a representative average value. This technique of determining downhole gas gravity is more accurate, less expensive and quicker.

CO_2 gas columns exert more pressure than most hydrocarbon gas columns because CO_2 gas is heavier (having a specific gravity of 1.53). Fig. 14 is the pressure traverse of CO_2 gas columns assuming the surface temperature is 100°F and the temperature gradient is 0.015°F/ft. Also, Table 3 can be used to determine the CO_2 gas column pressure. Interpolation will probably be required. Table 3 shows the depth of a column and the assumed temperature at that depth. The "pressure" column shows the pressures which would exist at different depths. The round trip travel time is shown. Check that the time shown agrees with actual acoustic chart travel time to verify the gas column is predominantly CO_2. Fig. 15 gives the acoustic velocity of CO_2 gas at different temperatures and pressures.

COMPUTER

Huddleston[12] discusses a portable computer for calculating acoustic static bottomhole pressures. Entered items include surface pressure, liquid level depth (or liquid level acoustic travel time), liquid production data, gas gravity (or composition including CO_2 and other non-hydrocarbon gases), temperature gradient, and formation depth.

The software determines the gas-column pressure from gas-composition data (or acoustic velocity data), oil column pressure (corrected for dissolved gas, pressure, and temperature), and water column pressure (corrected for dissolved gas, pressure, and temperature). The computer will also calculate bottomhole pressures in wells producing very high concentrations of CO_2 gas. With CO_2 gas, computer data input for surface and downhole temperatures should be 100°F or higher to prevent inconsistencies which will occur near the CO_2 critical temperature of 88°F.

The computer is certainly more versatile than the equation and charts procedure presented herein. Software also calculates depth from acoustic travel time when gas properties are known.

FIELD DATA AND CONCLUSIONS

Field results of calculated acoustic pressures vs. wireline downhole pressures are given for several wells in Table 2. Some have extremely high pressures and environments of corrosive gases and high temperatures.

Excellent results were obtained on almost all wells when gas and liquid properties were known. Calculated pressures were within ±1% of measured pressures. Expected accuracy is approximately that obtained with conventional wireline pressure recording devices.

Good results have been obtained on wells which produce very high concentrations of CO_2 when the gas is uniformly distributed from the surface to the formation. See acknowledgment. Medium-high concentration of H_2S and CO_2 and other non-hydrocarbon gases reduce the accuracy if settling of the heavy gases occurs and collars are not recorded all the way to the liquid level.

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ACKNOWLEDGMENT

Special thanks to Cities Service personnel for field data obtained on a CO_2 project located near Lindsay, Oklahoma, which had wells equipped with bottomhole pressure sensors.

Table 1
Oil and Water Gradients

API GRAVITY DEGREES	LIQUID GRADIENT PSI/FT
70	0.304
65	0.312
60	0.320
55	0.329
50	0.338
48	0.342
46	0.345
44	0.349
42	0.353
40	0.358
38	0.362
36	0.366
34	0.370
32	0.375
30	0.380
28	0.384
26	0.389
20	0.405
15	0.419
10	0.433
FRESH WATER	0.433
SALT WATER RANGE	0.477 0.500 0.520

$$\text{LIQUID GRADIENT, PSI/FT} = \frac{61.3}{\text{DEGREES API} + 131.5}$$

Table 2
Acoustic and Measured (Bomb) Pressure Data

DEPTH, FEET	SURFACE PRESSURE, PSIG	ACOUSTIC BOTTOM-HOLE PRESSURE, PSIG	BOTTOM-HOLE PRESSURE, BOMB NO. 1 PSIG	BOTTOM-HOLE PRESSURE, BOMB NO. 2 PSIG
10,600	5,610	7,585	7,583	—
10,600	6,065	7,864	7,874	—
9,736	5,012	6,005	5,954	—
13,792	8,485	10,294	10,347	10,425
9,359	1,193	1,467	1,459 (QUARTZ)	—
8,956	1,440	1,760	1,751 (QUARTZ)	—

Table 3
CO_2 Gas Column Pressure and Travel Time

DEPTH FT.	TEMP. F.	PRES. PSIA	TIME SEC.	PRES. PSIA	TIME SEC.	PRES. PSIA	TIME SEC.	PRES. PSIA	TIME SEC.	PRES. PSIA	TIME SEC.
0	100	200	0	400	0	600	0	800	0	1000	0
500	107	205	1.25	412	1.34	620	1.45	830	1.61	1047	1.91
1000	114	211	2.5	424	2.66	640	2.88	861	3.21	1096	3.79
1500	122	217	3.74	437	3.98	661	4.31	893	4.79	1146	5.63
2000	129	224	4.97	450	5.29	682	5.71	926	6.34	1196	7.44
2500	137	230	6.19	463	6.58	704	7.11	958	7.88	1248	9.21
3000	144	236	7.4	476	7.87	726	8.49	992	9.4	1301	10.95
3500	152	242	8.61	490	9.15	748	9.87	1026	10.91	1355	12.65
4000	159	249	9.81	503	10.42	770	11.22	1060	12.39	1410	14.32
4500	167	255	11	517	11.67	793	12.57	1095	13.86	1465	15.96
5000	174	262	12.18	531	12.92	816	13.91	1130	15.32	1522	17.57
5500	182	269	13.35	545	14.16	839	15.23	1166	16.75	1579	19.16
6000	189	275	14.52	559	15.4	862	16.55	1202	18.17	1637	20.71
6500	197	282	15.68	573	16.62	886	17.85	1239	19.58	1696	22.23
7000	204	289	16.84	588	17.84	910	19.14	1276	20.97	1755	23.73
7500	212	296	17.99	602	19.04	934	20.42	1314	22.35	1815	25.2
8000	219	303	19.13	617	20.24	959	21.69	1352	23.71	1876	26.64
8500	227	310	20.26	632	21.43	984	22.95	1391	25.05	1937	28.07
9000	234	317	21.39	647	22.62	1009	24.21	1430	26.38	1999	29.46
9500	242	324	22.51	663	23.79	1035	25.45	1469	27.7	2062	30.84
10000	249	332	23.63	678	24.96	1060	26.68	1509	29.01	2125	32.19

DEPTH FT.	TEMP. F.	PRES. PSIA	TIME SEC.	PRES. PSIA	TIME SEC.	PRES. PSIA	TIME SEC.	PRES. PSIA	TIME SEC.	PRES. PSIA	TIME SEC.
0	100	1200	0	1400	0	1600	0	1800	0	2000	0
500	107	1330	1.7	1551	1.25	1759	1.06	1964	.95	2168	.87
1000	114	1457	3.44	1699	2.52	1916	2.14	2127	1.91	2335	1.75
1500	122	1581	5.15	1845	3.78	2070	3.22	2287	2.88	2500	2.64
2000	129	1703	6.82	1988	5.04	2223	4.3	2446	3.85	2664	3.53
2500	137	1825	8.42	2130	6.29	2373	5.37	2603	4.82	2825	4.43
3000	144	1945	9.97	2269	7.52	2522	6.45	2758	5.78	2985	5.32
3500	152	2065	11.47	2408	8.73	2670	7.51	2911	6.75	3143	6.21
4000	159	2184	12.92	2545	9.92	2816	8.56	3064	7.71	3300	7.1
4500	167	2303	14.33	2681	11.1	2960	9.6	3214	8.66	3456	7.98
5000	174	2421	15.7	2816	12.25	3104	10.63	3364	9.6	3610	8.86
5500	182	2539	17.03	2950	13.37	3246	11.65	3513	10.54	3764	9.74
6000	189	2656	18.32	3083	14.48	3388	12.65	3660	11.47	3916	10.61
6500	197	2773	19.59	3216	15.57	3529	13.64	3807	12.39	4067	11.47
7000	204	2890	20.82	3347	16.64	3668	14.62	3952	13.3	4217	12.32
7500	212	3006	22.03	3478	17.7	3807	15.59	4097	14.2	4367	13.17
8000	219	3123	23.21	3609	18.73	3946	16.54	4241	15.09	4515	14.01
8500	227	3239	24.36	3739	19.75	4083	17.48	4384	15.97	4663	14.85
9000	234	3355	25.5	3869	20.76	4220	18.41	4526	16.84	4810	15.67
9500	242	3471	26.61	3998	21.74	4356	19.32	4668	17.7	4956	16.49
10000	249	3586	27.7	4126	22.72	4492	20.23	4809	18.55	5102	17.3

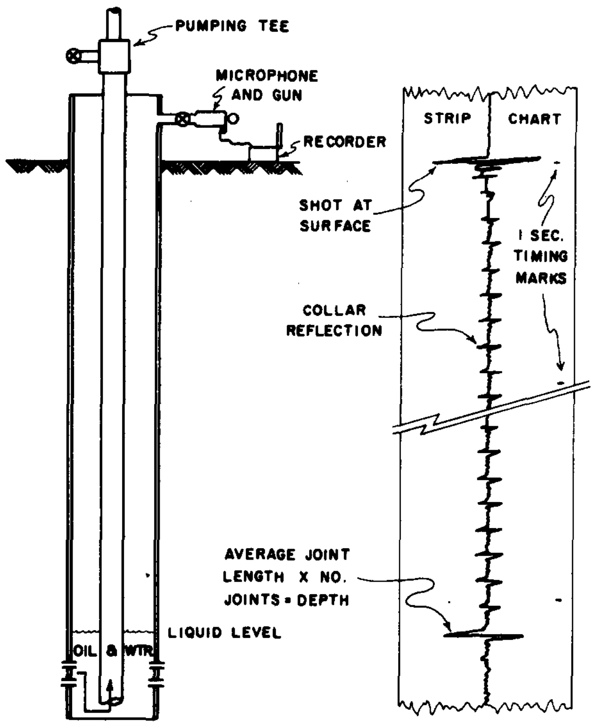


Figure 1 - Liquid level determination by acoustic instrument

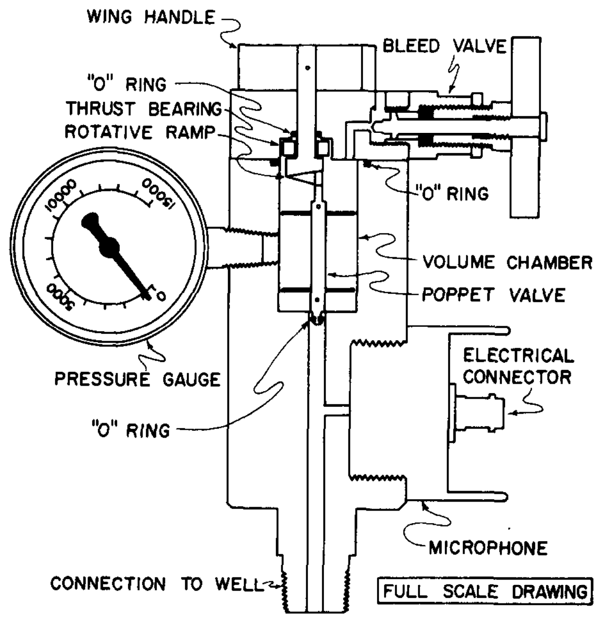


Figure 2 - High pressure gas gun

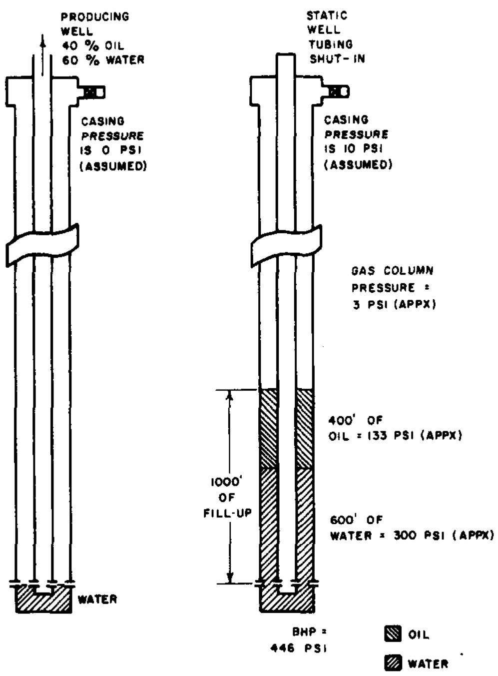


Figure 3 - Determining static bottom hole pressures - liquid level at formation while producing

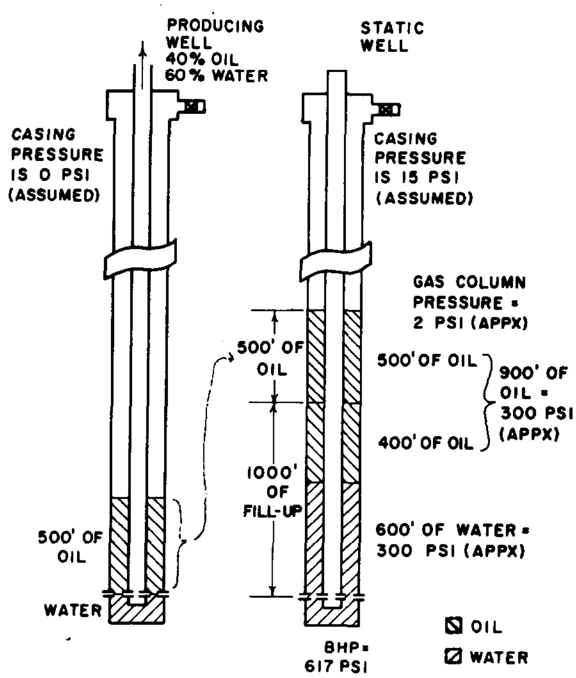


Figure 3A - Determining static bottom hole pressures - liquid level above formation while producing

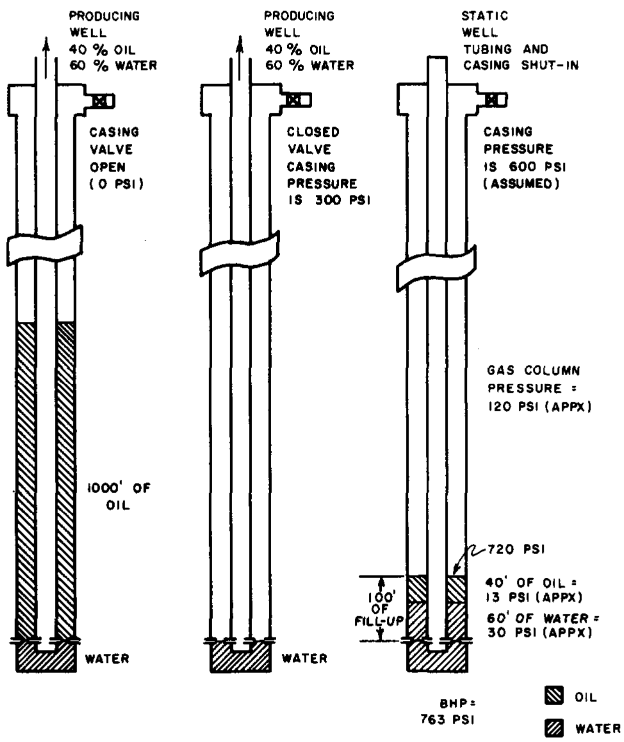


Figure 4 - Determining static bottom hole pressures. Improved technique when gaseous liquid level is above pump while producing.

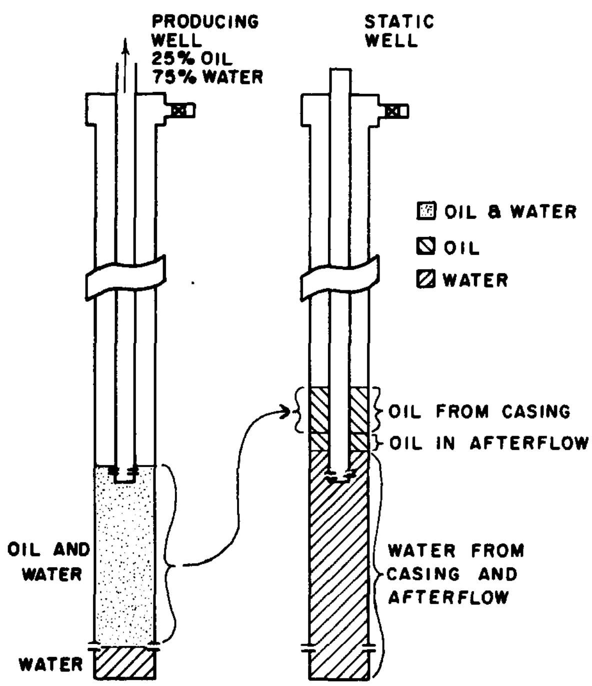


Figure 5 - Determining static bottom hole pressures. Liquid level at high pump.

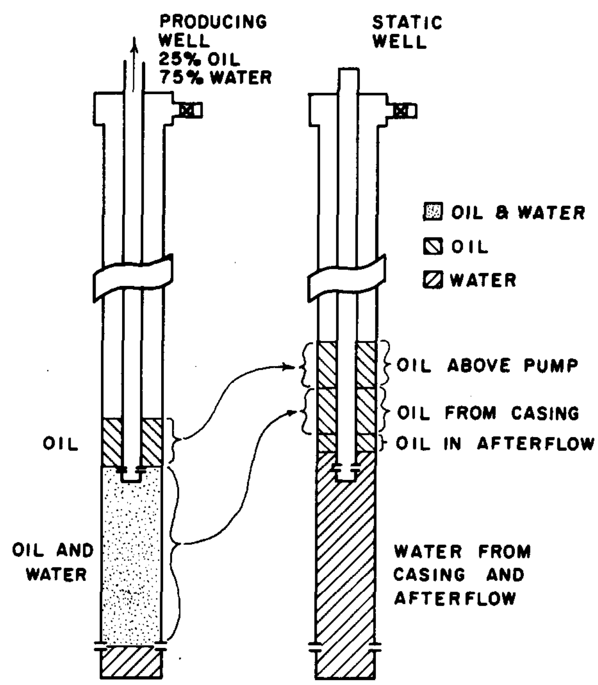


Figure 5A - Determining static bottom hole pressures. Liquid level above high pump.

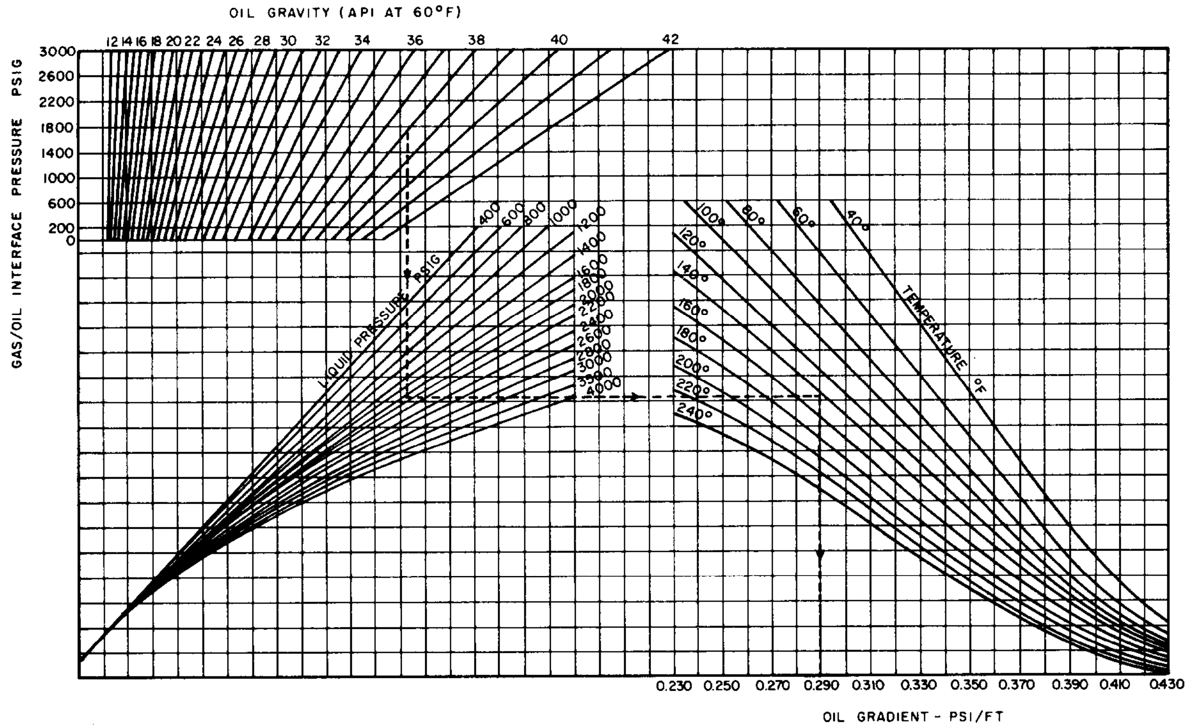


Figure 6 - Chart for estimating oil column pressure gradient (Energy Resources Conservation Board)

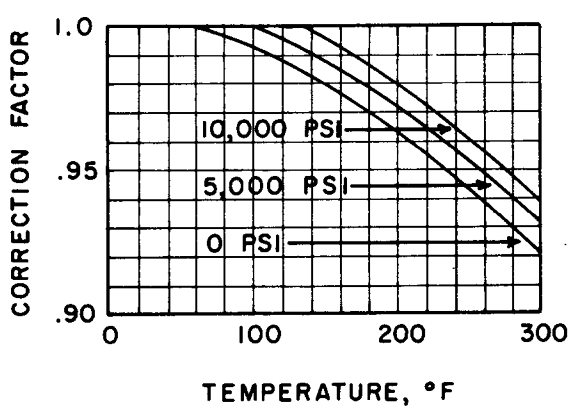


Figure 7 - Water correction factor

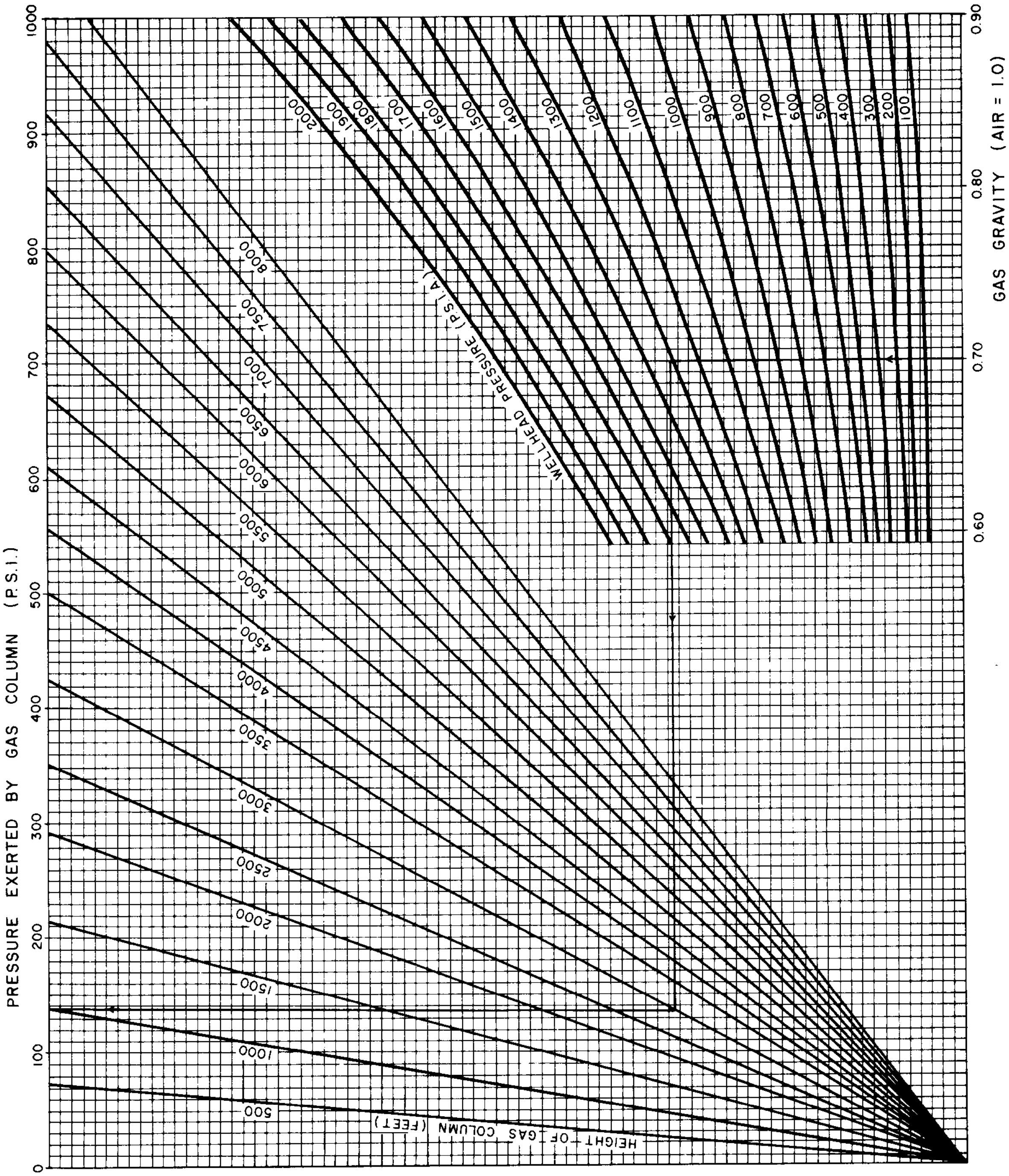


Figure 8 - Gas column pressure

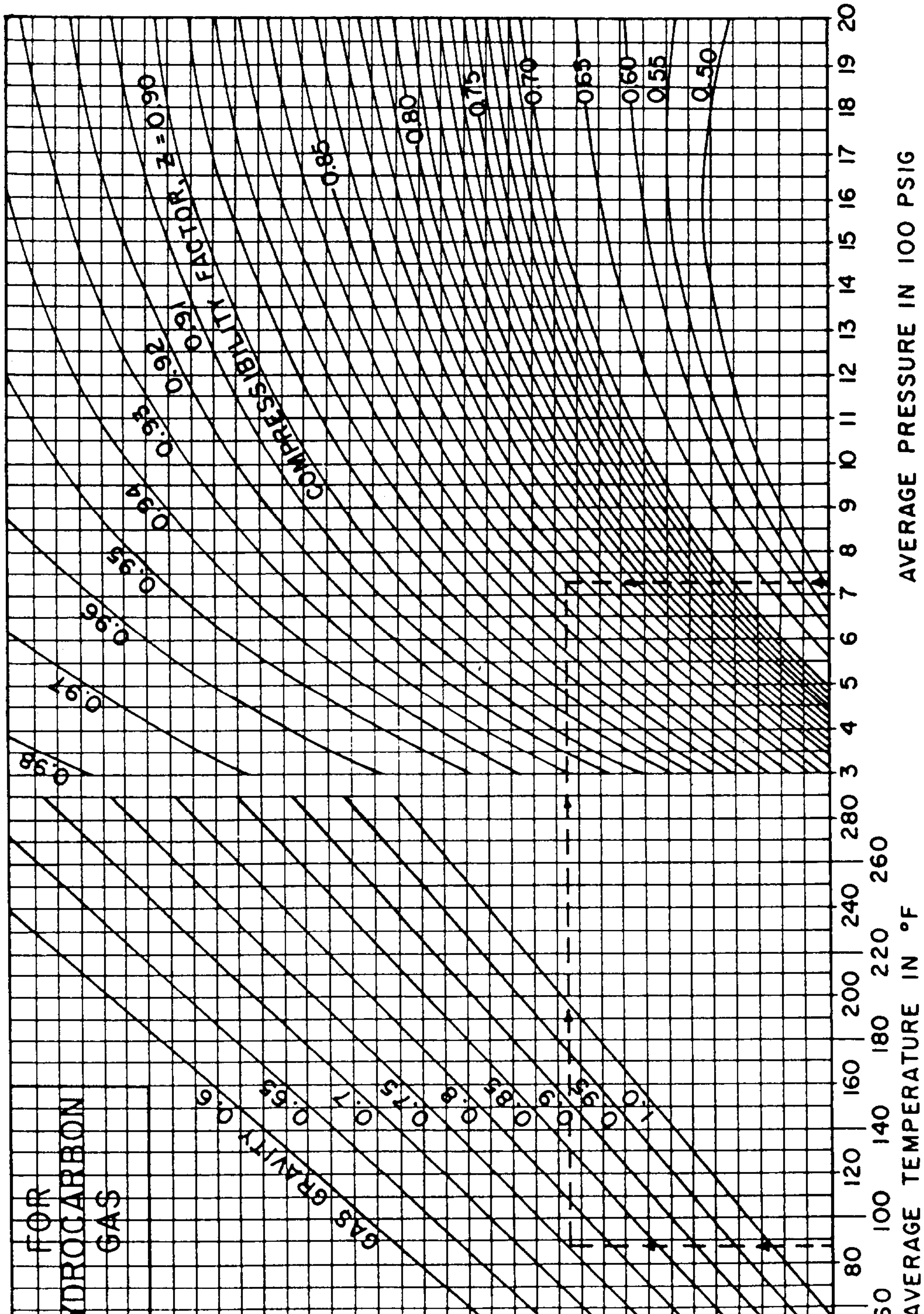


Figure 9 - Compressibility factor Z (Standing - Katz)

Example Problem of Gas Column Pressure Well Conditions

Surface Pressure = 2000 PSIA
Gas Gravity = 0.70
Surface Temperature = 70°F
Formation Temperature = 110°F
Formation Depth = 5000 Ft.
No liquid in well

Tc = 387°R (from Fig. 10)
Pc = 665 PSIA (from Fig. 10)

By Definition:

$$Tr = \frac{T}{Tc} = \frac{[(70 + 110) \div 2] + 460}{387} = 1.42$$

$$Pr = \frac{P}{PC} = \frac{2000}{665} = 3.01$$

Z = 0.72 (note, Pr is entered at top of Fig. 11)

$$Pgc = \frac{0.0188 \cdot 2000 \cdot 0.7 \cdot 5000}{0.72 \cdot (90 + 460)} = 332 \text{ psi}$$

Determine pressure at mid-point

$$2000 + \frac{332}{2} = 2166$$

Determine new Z factor

$$Pr = \frac{2166}{665} = 3.26$$

Z = 0.715

$$P = \frac{0.0188 \cdot 2166 \cdot 0.7 \cdot 5000}{0.715 \cdot (90 + 460)} = 362$$

Determine pressure at mid-point

$$2000 + \frac{362}{2} = 2181$$

Determine new Z Factor

$$Pr = \frac{2181}{665} = 3.30$$

Z - 0.715

$$P = \frac{0.0188 \cdot 2181 \cdot 0.7 \cdot 5000}{0.715 \cdot (70 + 460)} = 364$$

SBHP = 2000 + 364 = 2364 PSIA

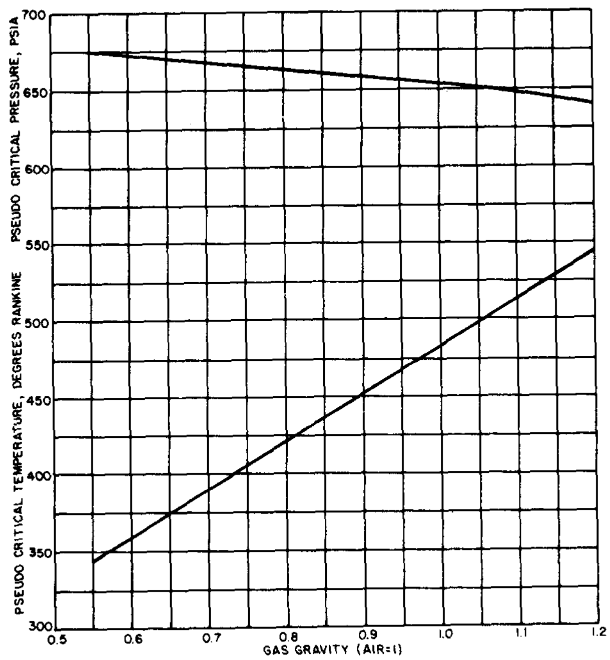


Figure 10 - Gas gravity vs. pseudocritical pressure and temperature.

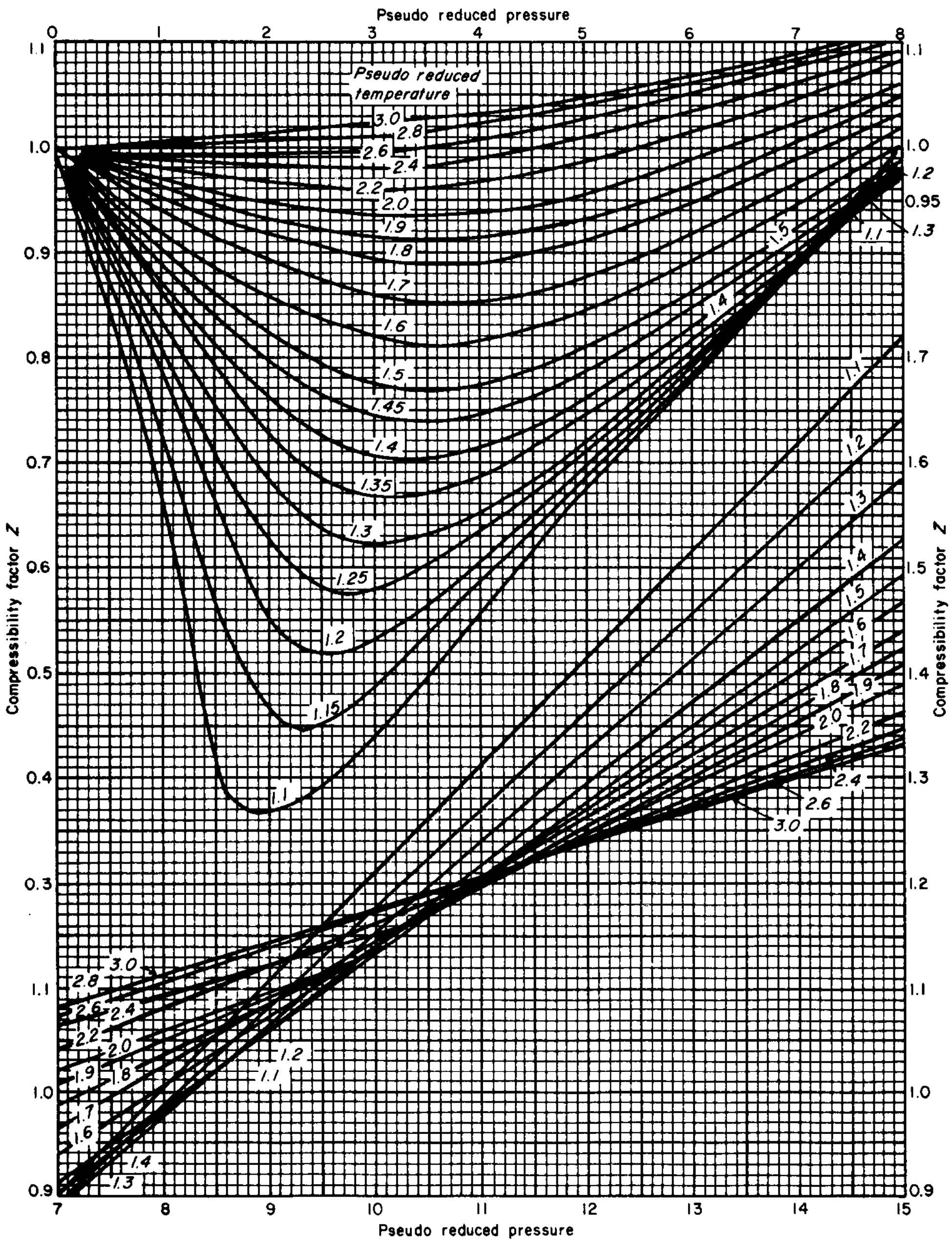


Figure 11 - Compressibility factor for natural gases.

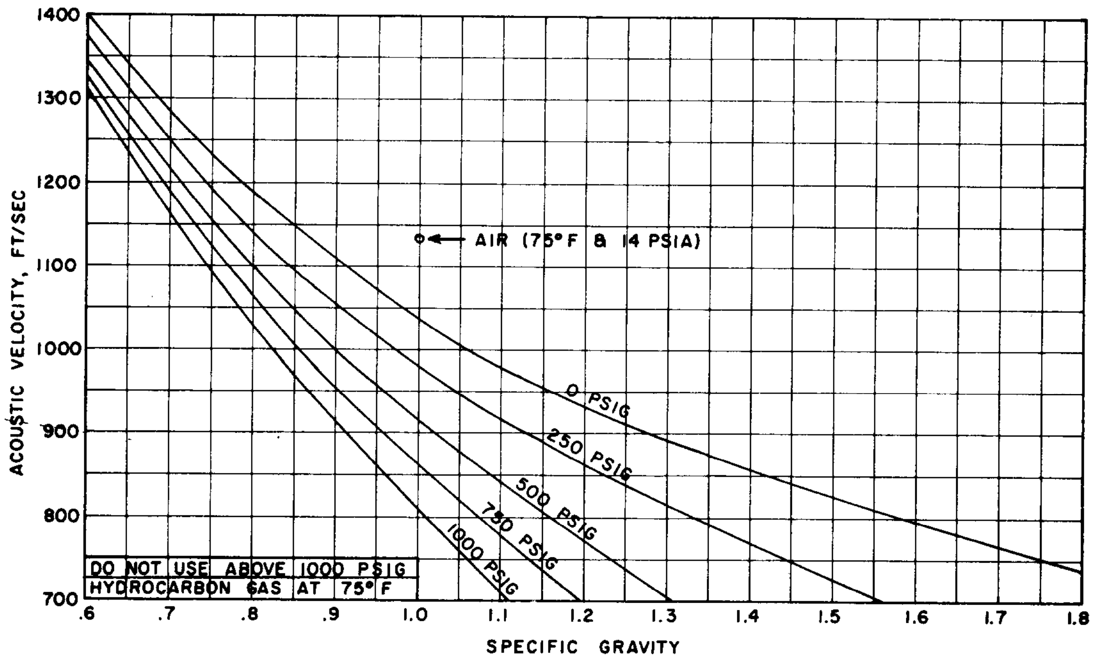


Figure 12 - Gas gravity as a function of acoustic velocity

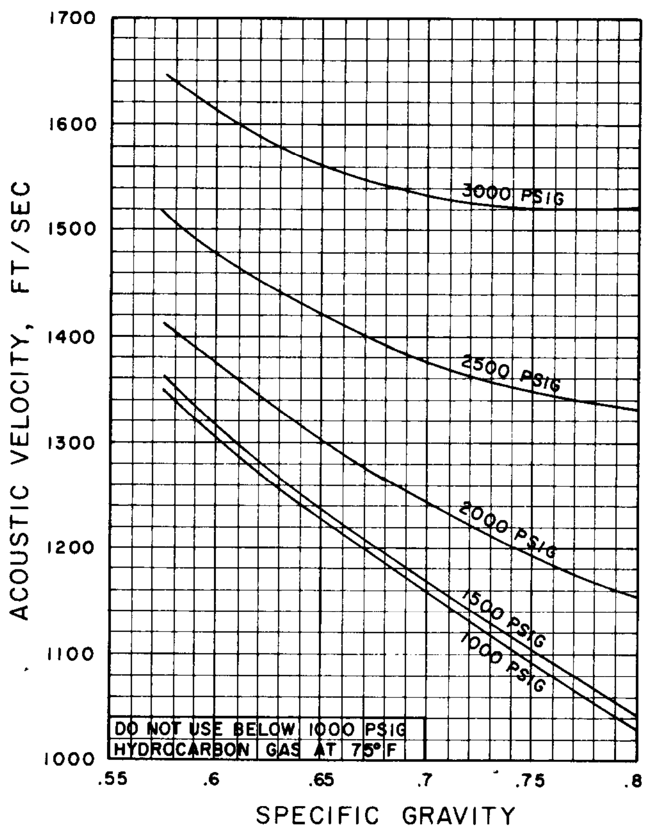


Figure 13 - Gas gravity as a function of acoustic velocity

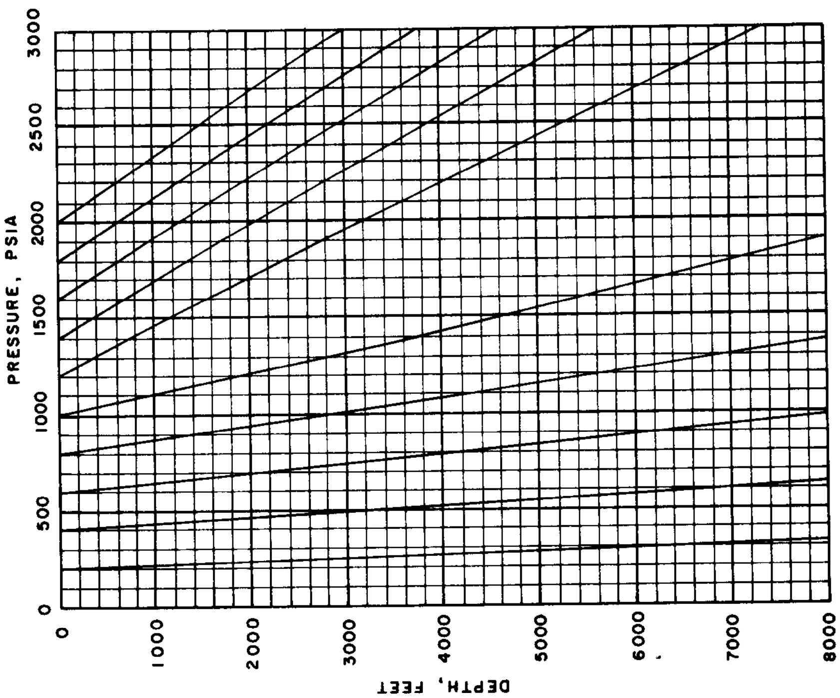


Figure 14 - CO_2 gas column pressure traverse

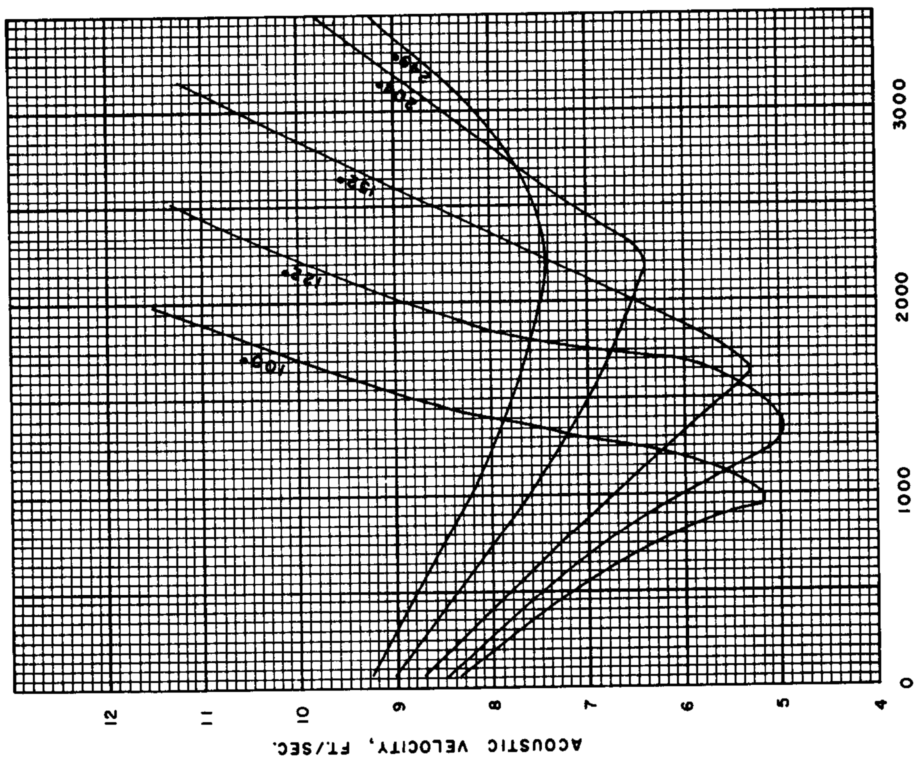
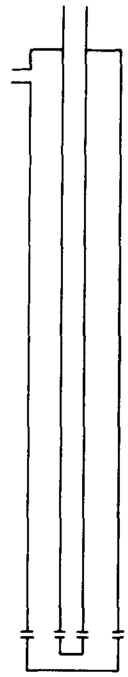


Figure 15 - CO_2 acoustic velocity

SBHP Calculation Sheet*



Well ____________________

Date ____________________

Shut-in time and Date ____________________

1. Casing Pressure, PSIG ____________________
2. Static Liquid Level, distance from surface, FT. ____________
3. Formation Depth (Pressure Datum), FT. ____________
4. Surface Temperature, F ____________________
5. Formation Temperature, F ____________________
6. Oil Gravity, API ____________________
7. Oil Gradient, psi ft ____________________
   use Table 1 or Figure 6
8. Water Specific Gravity ____________________
9. Water Gradient = ____________________ psi ft.

0.433 psi ft.	x	S.G.	x	Correction Factor
0.433 psi ft.	x	Item 8	x	Fig. 7
0.433 psi ft.	x	________	x	____________

10. Average Gas Column Temperature is ____________ F.
11. Acoustic Velocity = (Collars sec) x (Avg. Joint Lgt., Ft.) x 2 =
    ____________ x ____________ x 2 = ____________ Ft Sec
12. Gas Specific Gravity (use Fig. 8 or 9) ____________
13. Gas Column Pressure = ____________ psi

Pgc	0.0188	x	P	x	S.G.	x	L	÷ [	Z	x	T	]
	0.0188	x		x	Item 12	x	Item 2	÷ [		x	(Item 10 + 460)	]
	0.0188	x	(________)	x	________	x	________	÷ [	________	x	(________)	]

14. Well Production: BOPD = ____________ (14a) BWPD = ____________ (14b) BFPD = ____________ (14c)

15. Oil Column Pressure = ____________ psi

Height of liquid column	x	Oil Gradient	x	Fraction of Oil in Liquid Column		
(Item 3 − Item 2)	x	Item 7	x	Item 14a	÷	Item 14c
(________ − ________)	x	________	x	________	÷	________

16. Water Column Pressure = ____________ psi

Height of liquid column	x	Water Gradient	x	Fraction of Water in Liquid Column		
(Item 3 − Item 2)	x	Item 9	x	Item 14b	÷	Item 14c
(________ − ________)	x	________	x	________	÷	________

SBHP = ____________ PSIG

Casing Pressure	+	Gas Column Pressure	+	Oil Column Pressure	+	Water Column Pressure
Item 1	+	Item 13	+	Item 15	+	Item 16
________	+	________	+	________	+	________

*Producing Liquid Level at Pump which is at Formation.