SHOOTING FLUID LEVELS IN A CO_2 FLOOD

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ABSTRACT

In 2014 Oxy identified systematic accuracies in fluid level measurements in CO_2 wells and ceased making them. Echometer and Oxy collaborated to identify the root cause of the fluid level inaccuracies and resolved the issue through improved procedures and educating personnel. Today trusted fluid level data has improved operational decision making.

INTRODUCTION

Oxy operates the most beam pumped wells undergoing CO_2 flooding in the global petroleum industry. In 2014, Oxy was no longer shooting fluid levels on CO_2 wells because the data were inconsistent and had lost credibility. In 2015, Echometer Company was contacted, as one of the company's engineers had extensive experience in the Seminole San Andres Unit CO_2 Flood. The plan was to shoot fluid levels in 25 wells in the Denver Unit that had both electric submersible pumps (ESPs) and downhole pressure sensors. The electronic files containing the fluid level shots were sent to Echometer for analysis.

BACKGROUND

A 12-well study[1] had previously been conducted during a 30-hour period in 1996 at the Seminole San Andres Unit CO_2 flood, where the fluid level in the casing annulus was depressed toward the pump intake by shutting in the casing valve to increase casing pressure. Only ESP wells having downhole pressure sensors were included in the study. When the casing valve was closed, frequent fluid level measurements were acquired as the casing pressure increased and the fluid level was depressed[2] toward the pump.

C.P. Walker[3,4] developed a process for determining the producing bottomhole pressure in wells that had gaseous liquid columns. Plots of the height of the gassy liquid level versus the gas/liquid interface pressure show a straight line, with the slope of the line representing the gradient of the gassy fluid below the liquid level.

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 backpressure valve and stabilized. The data in this study were 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 each well's downhole ESP pressure sensor.

The fluid level depression test provided characteristics of the gassy fluid column in each well that allowed the wells to be sorted into groups based on the specific behavior of the gassy fluid columns. **Fig. 1** is an example of CO_2 flood wells where the producing bottomhole pressure was low and the surface pressure was low. When the producing bottomhole pressure is below 600 psig, then the pump intake pressure from the fluid level analysis typically matches the ESP pump intake sensor reading. When the producing bottomhole pressure was below 600 psig, then these types of CO_2 wells behave similarly to a standard oil well producing hydrocarbon gas.

Fig. 2 wells have a high gassy fluid level, but are not flowing liquid to the surface up the casing annulus. When the producing bottomhole pressure is above 600 psig, too light of a gassy fluid column gradient is determined, causing the pump intake pressures from the fluid level analysis to be much lower than the ESP pump intake sensor reading. **Fig. 3** shows wells that have very high fluid levels with both gas and liquid flowing up the casing annulus to the surface. Wells in this group are the most difficult to identify the fluid level at the surface. Due to the noise from fluid flowing at the surface, the software's automatic selection of the fluid level depth is often incorrect.

Fig. 4 compares the pressure gradients of CO_2 gas, hydrocarbon gas without CO_2, and 35°API oil at the Seminole San Andres reservoir temperature. At flowing BHP > 600 psi and temperature around 100°F, the density of CO_2 increases rapidly and approaches the density of 35°API oil. The CO_2-oil mixture behaves essentially as if it were oil when the flowing bottomhole pressure increases above 1500 psi. The difference in density and miscibility characteristics of CO_2 and 35°API oil result in relatively the same gradient. When the pump intake pressure is below 600 psi, then the CO_2 behaves very much like a hydrocarbon gas, and fluid level pump intake pressures compare well with pump intake pressures of ESP downhole sensor readings.

DETERMINING THE DISTANCE TO THE LIQUID LEVEL

Determining the distance to the liquid level is done automatically by the software using the default method of counting uniformly spaced tubing collar echoes. The distance to the liquid level is determined by multiplying the average joint length input into the software by the number of joints to the liquid level. The round trip travel time is used to determine the average acoustic velocity of the casing annulus gas above the liquid level.

Echometer Company provides free downloads of a paper[5] that shows the acoustic velocity of four (4) different hydrocarbon gas mixtures at various pressures and temperatures. CO_2 gas with a specific gravity of 1.516 is heavier than the hydrocarbon gas mixtures shown in the paper on Acoustic Velocity of Natural Gas. **Fig. 5** shows how the percent of CO_2 affects the acoustic velocity of a typical hydrogen gas present in a CO_2 flood. Most CO_2 floods have near 100% CO_2 present in the produced gas from each well; therefore, the acoustic velocity for active CO_2 floods is near 850 ft/sec. A quick validity check is to compare the acoustic velocity determined from counting collars with an acoustic velocity interpolated from **Fig. 5**. If the acoustic velocity determined by counting collars is not within 5-10% of that interpolated from Fig. 5, then the automatic fluid level depth determination should be re-examined step by step to identify a possible error.

25-WELL STUDY

The analysis of the fluid levels initially performed by Oxy were reviewed by Echometer, which identified that 25% of the fluid levels had problems in the initial analysis. The sources of inaccuracy were identified as follows:

- Oxy personnel shooting fluid levels were very inexperienced and had not had sufficient training.
- Oxy personnel did not have the skills to interpret the difficult fluid level shots and depended upon the automatic software analysis done by the computer to calculate the distance to the fluid level.
- Well data were sometimes left blank or default values were used, including average joint length, gas composition, and tested well production rates.
- Wellbore information was not input correctly, including the known downhole wellbore changes in cross-sectional area and any markers. Also, the fluid level analysis was not adjusted to account for depths to known marker reflections.
- Wells flowing up the casing annulus with liquid levels at or near the surface were not identified.
- Software defaulted to round trip travel time of 8.5 seconds when high fluid levels were not recognized.
- Compressed CO_2 gas in a cylinder was used to charge the gas gun to create the pressure in the well and produce a usable acoustic trace in the gas above the liquid level. In some cases, the charge pressure was not significantly different from the surface casing pressure, resulting in an inadequate energy pulse to produce a usable acoustic trace to determine an accurate fluid level.

In the study, several significant issues were identified:

1) The Pump Intake Pressure (PIP) of the ESP was compared to the liquid level calculated by the fluid level shot. **Fig. 6** shows that below 600 psi, pump intake pressures determined using acoustic instruments correlate well with the pump intake pressures read from the ESP sensor. This seems consistent with **Fig. 4**, which shows that CO_2 has similar characteristics to a hydrocarbon gas below 600 psi, and above 1800 psi CO_2 acts like a liquid hydrocarbon. The data collected in this study agree with **Fig. 4:** The CO_2 fluid levels measured with pump intake pressures below 600 psi show that CO_2 acts like gas. Fluid levels taken with PIP above 600 psi are more difficult, because the CO_2 is partially liquid and partially gas. **Fig. 7** shows how the gradient changes with CO_2 composition. Note that at 99.9% CO_2 the transition from mostly liquid characteristics to mostly gas characteristics occurs rapidly, with a change of pressure from approximately 1050 to 1100 psi.

2) Wells with gradients less than 0.08 psi/ft are likely flowing up the backside of the well. A 5,000-ft San Andres well is likely flowing up the backside when the minimum flowing bottomhole pressure exceeds 400 psia with 0 psi casing pressure. (See Fig. 8.)

3) Fig. 9 shows the pressure buildup adjustment factor, which is essentially the ratio of CO_2 gradient to the hydrocarbon gas gradient for various pressures. A polynomial equation is used to calculate the ratio of CO_2 gradient to the hydrocarbon gas gradient. For pressures less than 600 psi, it is reasonable to assume a value of two. Fig. 9 shows that when calculating the CO_2 gas inflow rate using the casing pressure buildup technique, the buildup pressure should be divided by 2.

On wells with high fluid levels that are difficult to shoot, Echometer recommends performing a Fluid Level Depression Test.[6] For a rod-pumped well, this test consists of installing a back-pressure regulator on the backside/casing. The casing pressure is then adjusted to three or more different settings (at least 50–100 psi apart), and the well is allowed to stabilize. Then the fluid level is shot several times at each stabilized casing pressure. Typically, low-rate artificially lifted wells required the use of a back-pressure valve. This modified Walker procedure can be used to determine the pressure of ESP wells when the production rate is higher than the liquid displaced out of the annulus. Using the Walker Fluid Level Depression test will enable an operator to estimate the producing bottomhole pressure accurately and estimate the incremental production that can be gained by upsizing the equipment. (See **Fig. 11** and **Fig. 12**.)

RECOMMENDATION

The following guidelines for shooting accurate fluid levels in CO_2 applications are recommended:

- During normal circumstances with wells in close proximity, it would be reasonable for an experienced person to shoot and analyze 8-12 wells per day.
- At no time during the pumping cycle should the bottomhole pressure be more than 10% of the static reservoir pressure.
- Measure the fluid level just before a well cycles on, rather than just after it cycles off, so you can calculate the % of static bottomhole pressure accurately.
- The pressure buildup portion of shooting a gas-free fluid level should take two minutes or less, if all the points plot on a straight line.
- Fluid level guns should be cleaned at least every 6 months.
- Always take at least two shots per well.
- Store the electronic copy of the fluid level shots at a location accessible by field personnel so everyone can look at them and others can review the analysis. Make sure the owner of the data has “write” access, whereas others probably should have “read only” access.
- Perform a quality check on the fluid levels. If there is a question, accessing and reviewing the electronic file could enhance credibility or identify a problem.
- The bottom perforation in a vertical well should be input as the formation depth. If you change your reference depth, then there will be a shift in the calculated pressures.
- On wells with high fluid levels that are difficult to shoot, a Fluid Level Depression Test should be performed, which consists of installing a back-pressure regulator on the backside/casing. The casing pressure is then adjusted to three or more different settings (at least 50–100 psi apart), and the well is allowed to stabilize. The fluid level is then shot several times at each stabilized casing pressure. Accurately estimating the producing bottomhole pressure and estimating the incremental production that can be gained by upsizing the equipment will prevent bad decisions based on incorrectly analyzed data.
- When shooting fluid levels in wells with high concentrations of CO_2, replace the pressure buildup with ½ the pressure buildup, i.e., divide it by 2.

REFERENCES

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2. McCoy, J.N., Echometer Company; Podio, A.L., University of Texas at Austin; Rowlan, O.L., Amerada Hess Corporation; and Garrett, M., Yates Petroleum: Acoustic Foam Depression Tests, 48th Annual Technical Meeting of the Petroleum Society in Calgary, Alberta, Canada, June 8-11, 1997.
3. Walker, C.P.: Method of Determining Fluid Density, Fluid Pressure and the Production Capacity of Oil Wells, U.S. Patent No. 2,161,733, June 6, 1939.
4. Walker, C.P.: Determination of Fluid Level in Oil Wells by the Pressure-Wave Echo Method, *Transactions of AIME,* presented at the Los Angeles Meeting, October 1936.
5. McCoy, J.N., Acoustic Velocity of Natural Gas, http://echometer.com/TechnicalPapers/tabid/83/Default.aspx
6. McCoy, J.N., Podio, A.L., and Huddleston, K.: Acoustic Determination of Producing Bottomhole Pressure," *SPE Formation Evaluation*, September 1988, pp. 617-621.

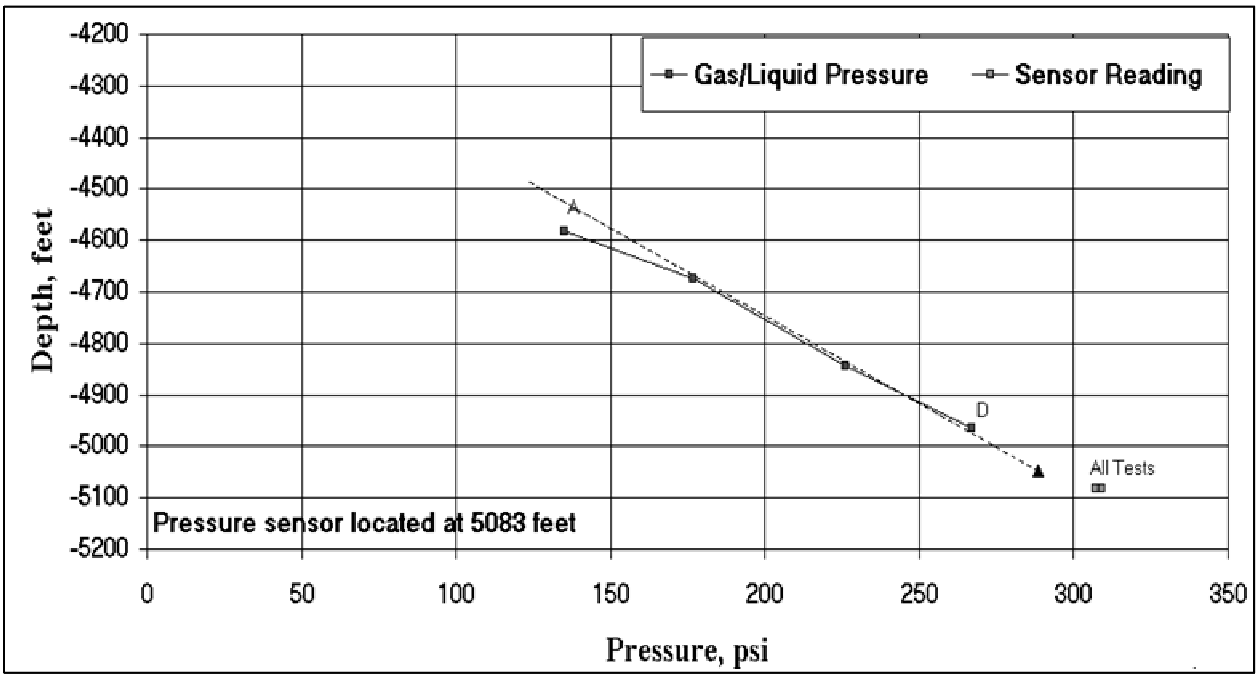

Figure 1 – Well No. 4313 – Casing Pressure Low and Fluid Level Near Pump

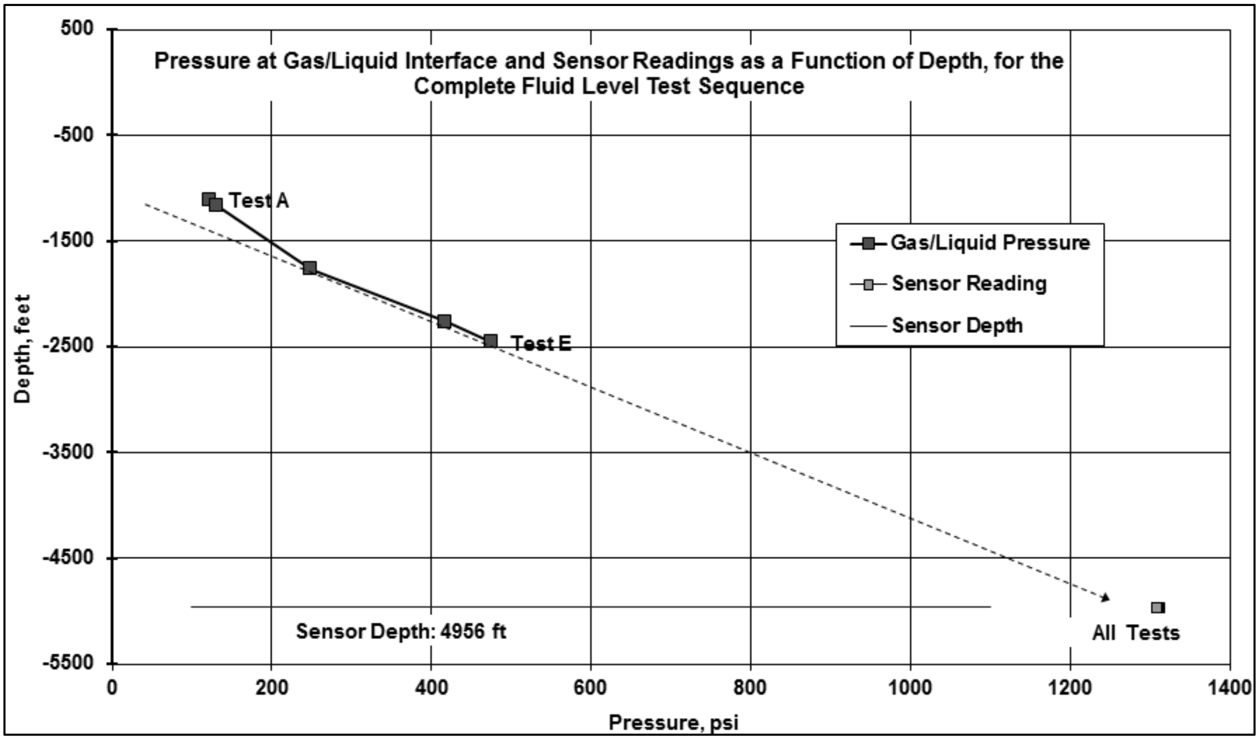

Figure 2 – Well 5523 – High Gassy Fluid Level and High Pump Intake Pressure

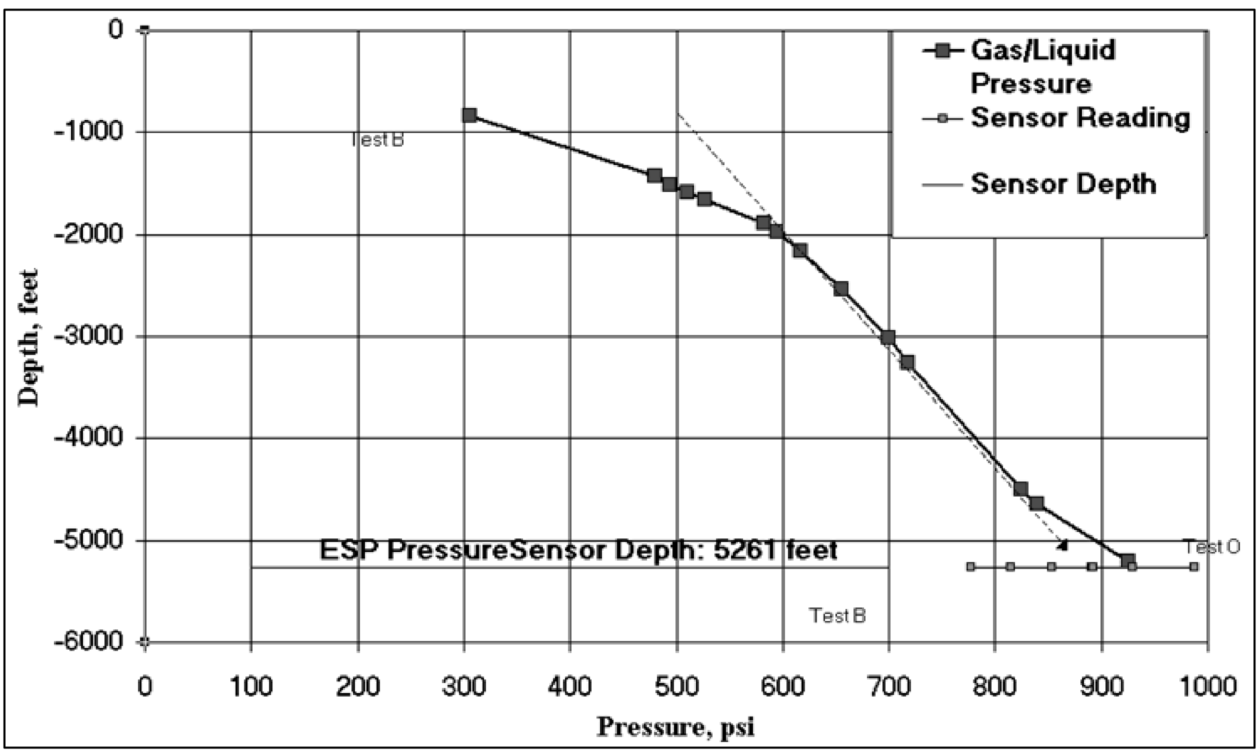

Figure 3 – Well No. 5518 – Liquid Flowing Up Casing

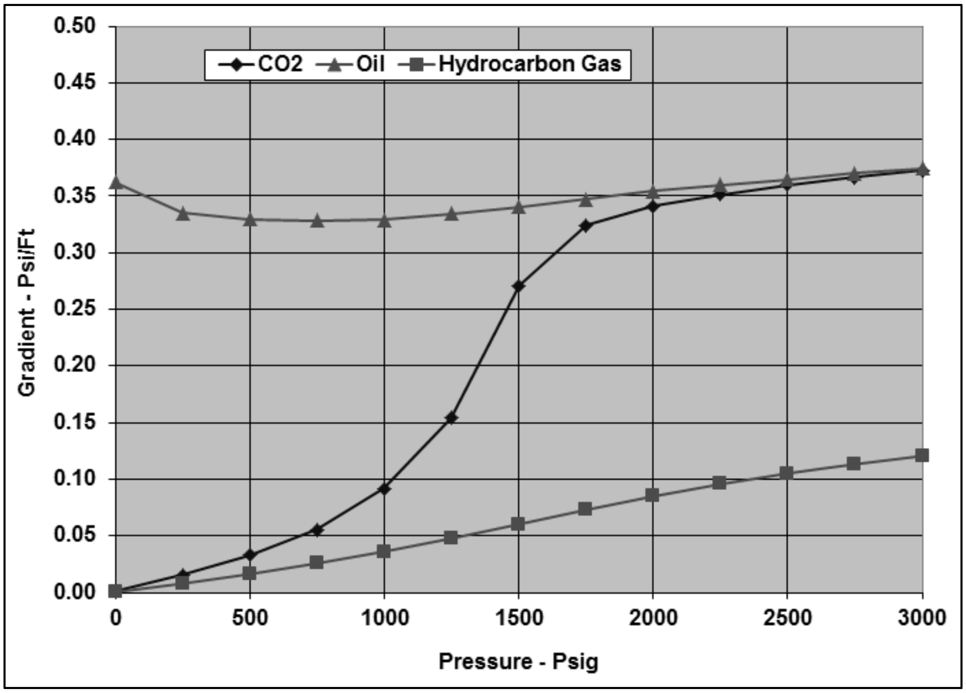

Figure 4 – Pressure Gradient Comparison: Hydrocarbon Gas vs. CO_2 vs. Oil

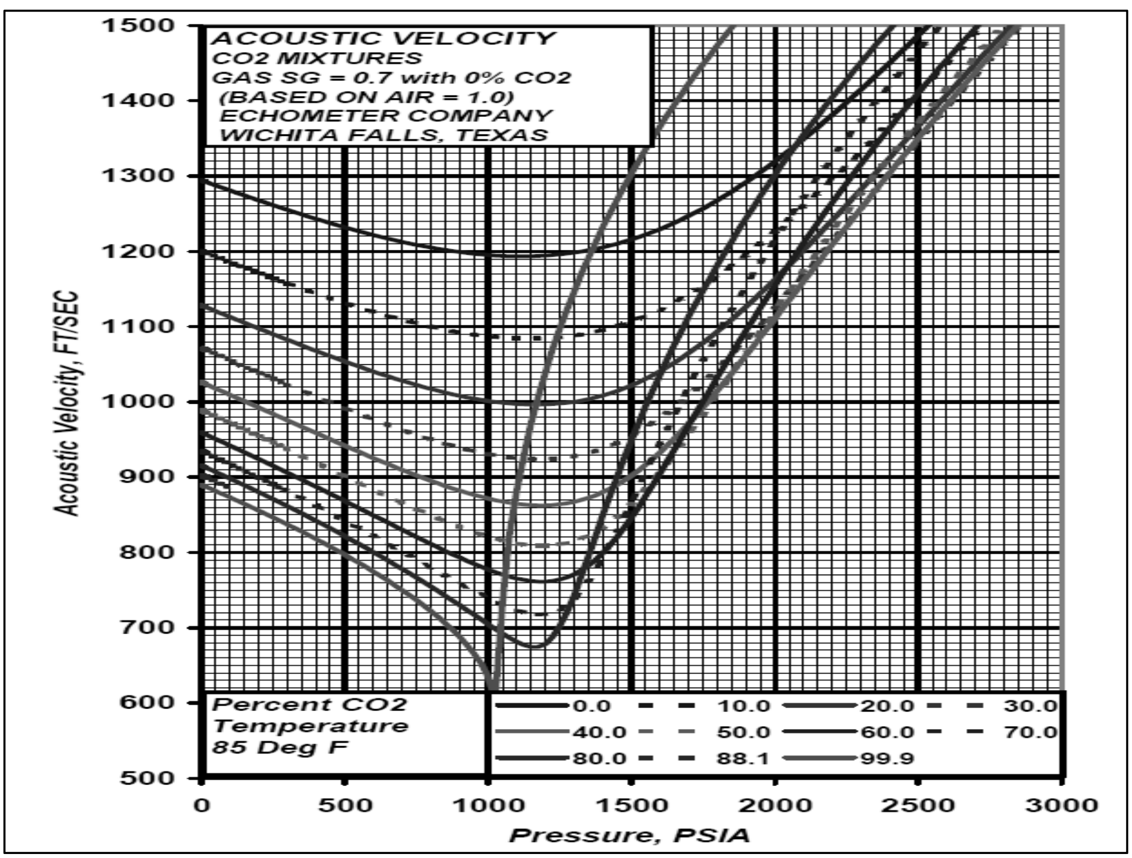

Figure 5 – Impact of Percent CO_2 on the Acoustic Velocity of Gas

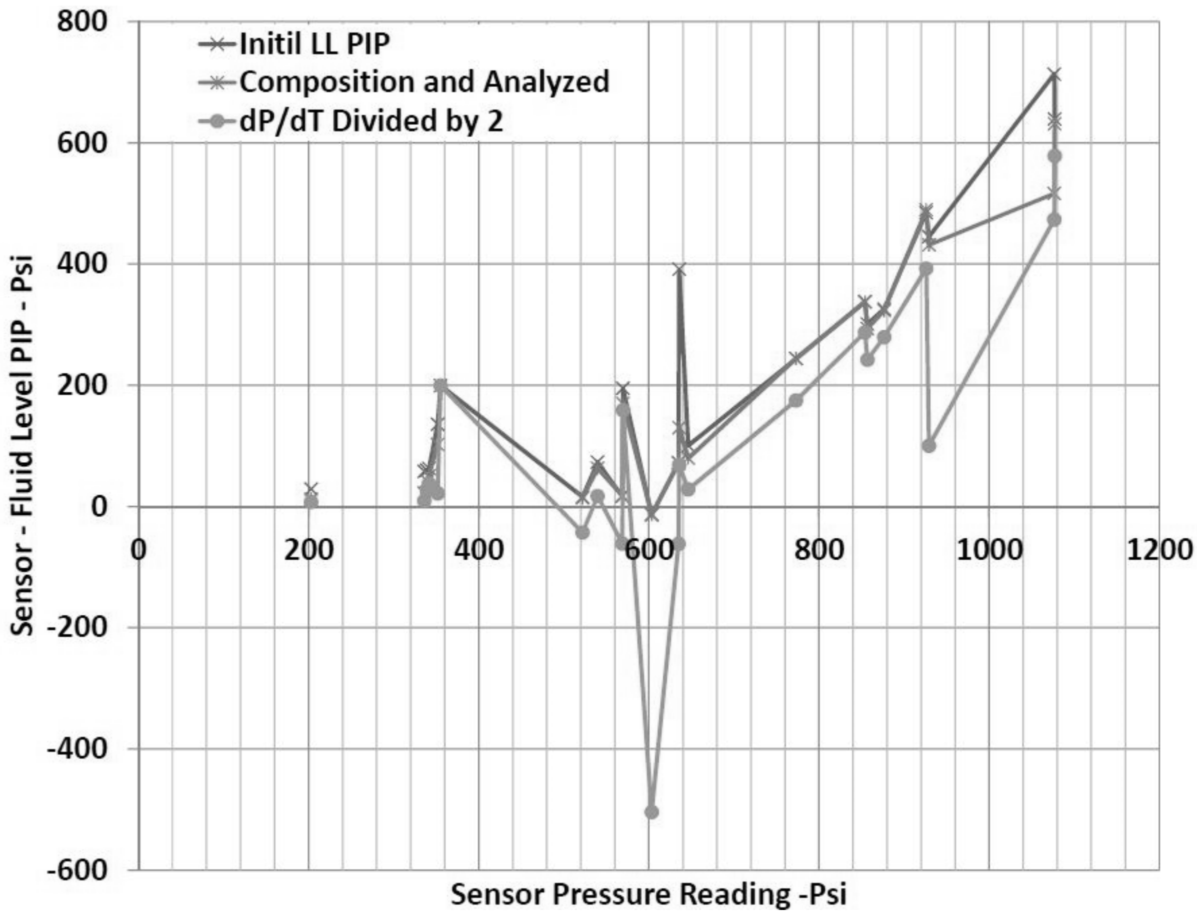

Figure 6 – Fluid Level-Determined Pump Intake Pressures Are Reasonable When PIP Is Less Than 600 psig

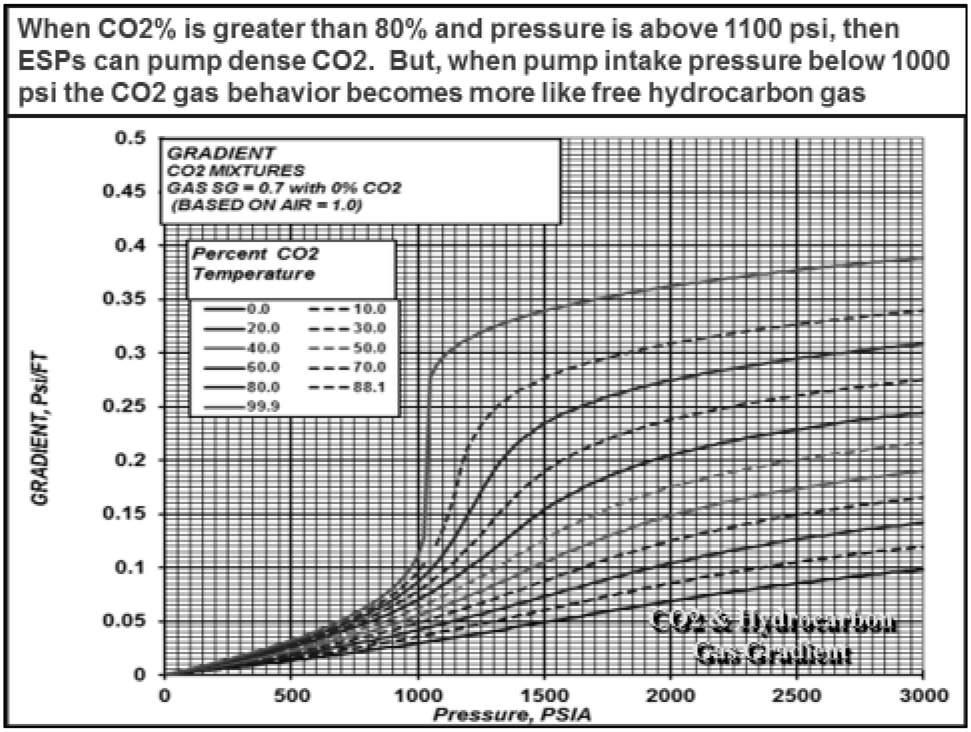

Figure 7 – Impact of Percent CO_2 on Gradient

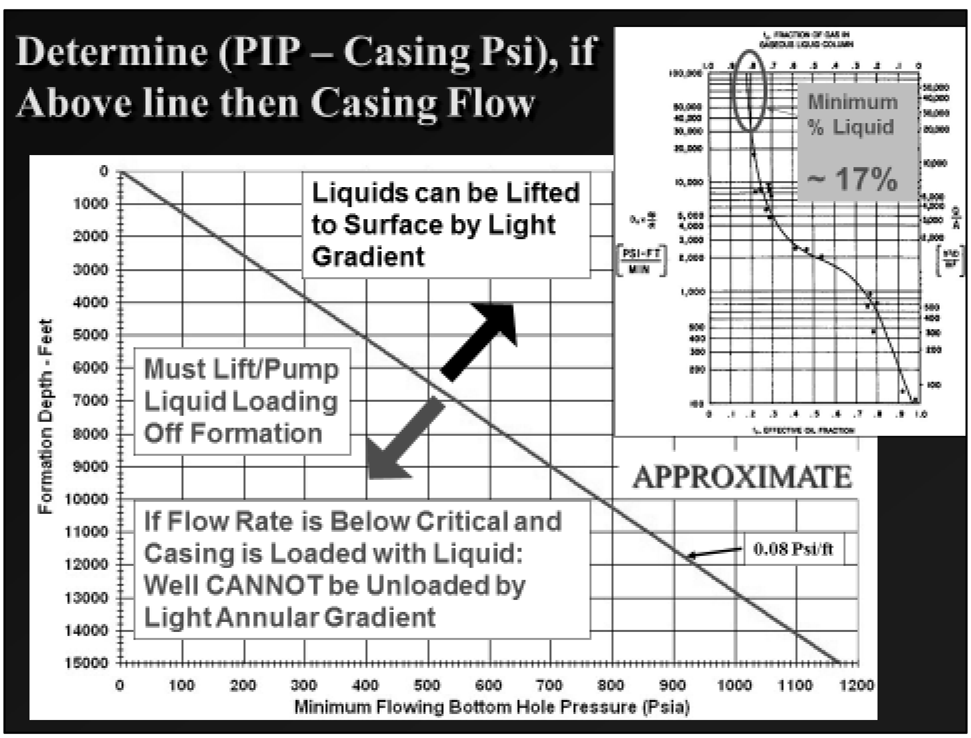

Figure 8 – Minimum Pump Intake Pressure Required to Lift Gassy Fluid Column to Surface

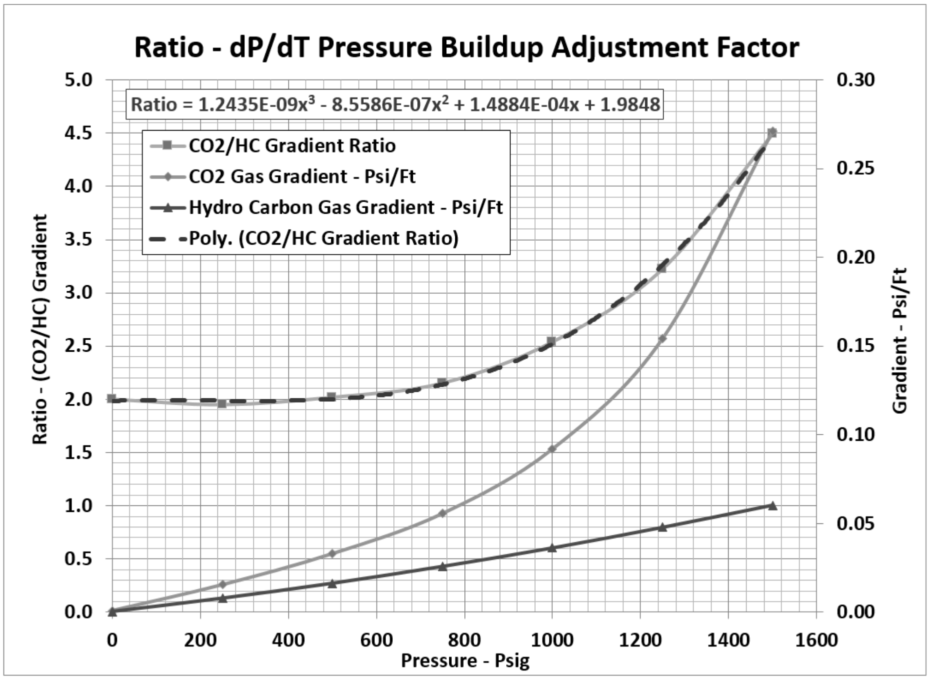

Figure 9 – dP/dT Pressure Buildup Adjustment Factor

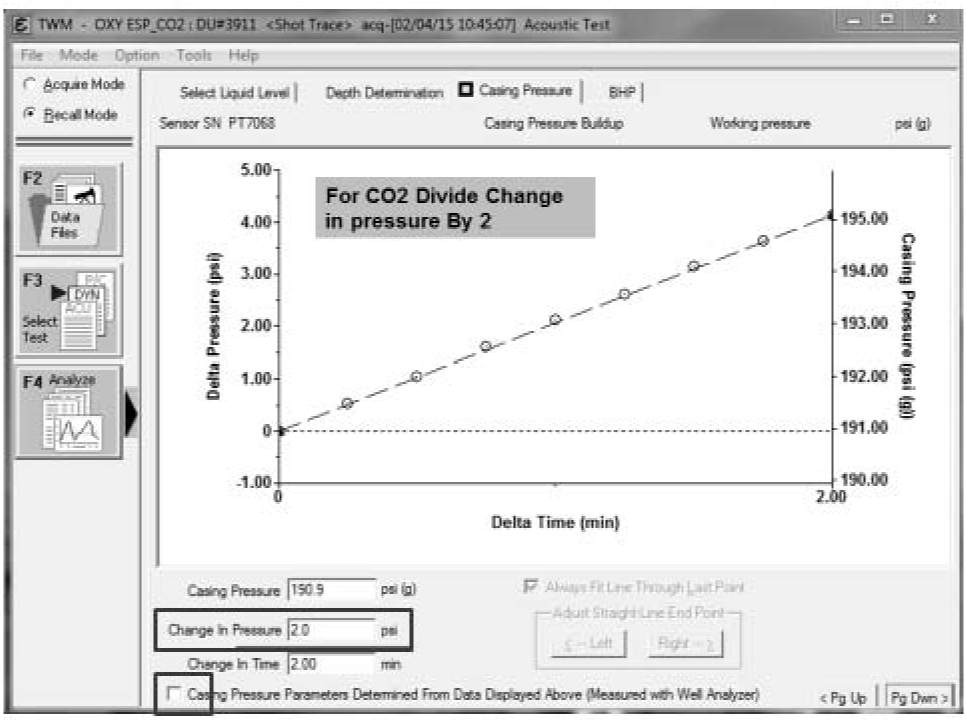

Figure 10 – dP/dT Divided by 2

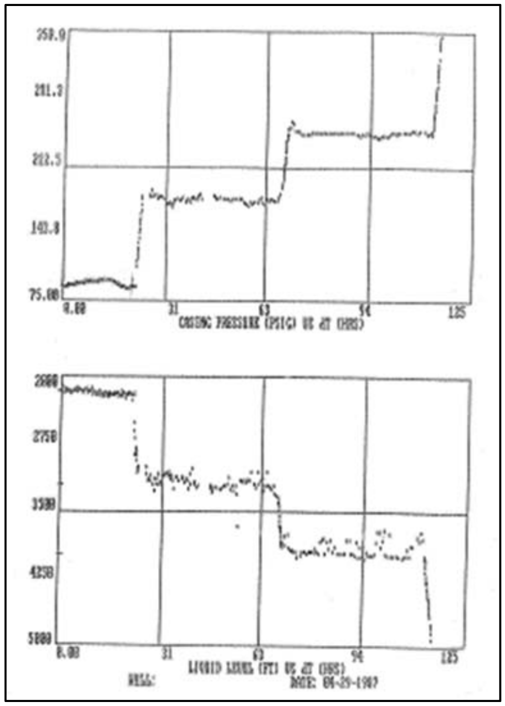

Figure 11 – Casing Pressure and Fluid Level Depression Test with Back-Pressure Valve

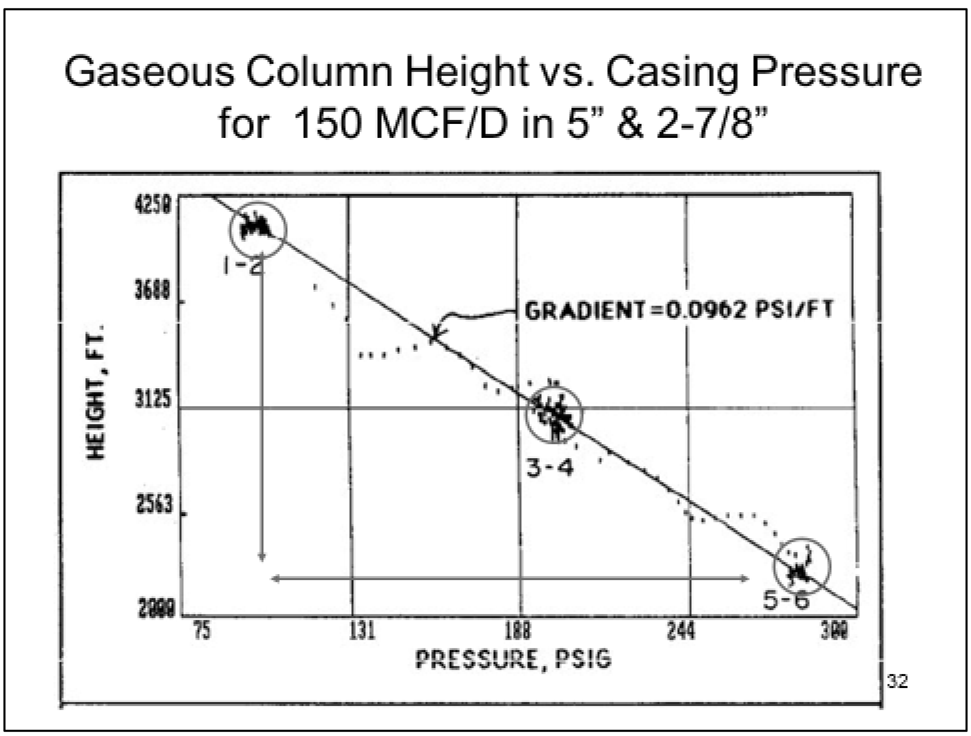

Figure 12 – Pump Intake Pressure Accurately Determined Using Depression Test