

The Influence of Equilibrium Water on Gas-Well Productivity

F.B. Thomas*, E. Shtepani, D.B. Bennion
Hycal Energy Research Laboratories Ltd.

J. Rushing
Anadarko Petroleum Corporation

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ABSTRACT

The economic due diligence that determines the price to pay for a gas property can be sensitive to the time value of money. This calculation is therefore intimately linked to predicting flow rates. With the invention of highly sensitive technology, gas-phase viscosities can now be measured accurately. This enables the investigation of previously ignored effects such as the influence of equilibrium water vapor on gas-well deliverability.

This paper discusses the technology of gas-phase viscosity measurement and then compares existing literature data. The paper then presents, by means of a case-history, the influence of water of condensation on viscosity and concomitantly on production rates.

Moreover, material-balance calculations are provided that show the role of water vapor in gas properties evaluation.

It is concluded that calculated gas flow rates can be significantly impacted by incorporating the influence of equilibrium water vapor whereas the influence of water vapor on gas in place is minimal.

BACKGROUND

Gas-phase properties measurement has been the subject of much research for many years. Lee and Eakin, Eakin and Ellington, Giddings and Kobayashi and Saeedi and Rowe¹⁻⁴ report early gas-phase measurements of viscosity and density along with correlations for each. Each of these references was at conditions less than

10,000 psi and without water content. Lee⁵ assembled a large body of gas-phase data that have been very useful for practitioners in the oil industry for many years. The Gas Processors data book⁶ has also been widely used but the limits of application have needed to be updated in light of much higher pressure reservoirs. Moreover, the measurements of rheological properties in the presence of water have not been made.

Due to the paucity of density and viscosity data available at high pressures and the influence of equilibrium water on these parameters, testing was initiated at Hycal Energy Research Laboratories Ltd. to investigate these parameters.

EXPERIMENTAL PROGRAM: VISCOSITY

Cambridge Applied Systems developed a viscometer based on measuring the resistance to movement of a piston when in the presence of a magnetic field. Figure 1 shows a schematic of the apparatus. The drive level of the magnet is adjusted to where the magnetic field causes movement of the piston through the fluid in the viscometer and the time of travel is recorded. The greater the difference between the travel time for the highest expected viscosities and the lower viscosities, the more sensitive the viscosity measurements will be. Thus, the recommended calibration protocol is to minimize the drive level and then measure the travel time and calibrate travel time to viscosity based upon some known viscosity standards.

The equations that govern the calibration are shown as Equations 1, 2 and 3. Equation 1 is a simple linear expression relating travel time to viscosity, whereas Equations 2 and 3 are quadratic expressions defining the dependence of α and β on travel time.

$$\mu = \alpha t + \beta \quad (1)$$

$$\alpha = a_1 t^2 + b_1 t + c_1 \quad (2)$$

$$\beta = a_2 t^2 + b_2 t + c_2 \quad (3)$$

where α and β are functions of travel time as well. The procedure was, therefore, to use regression to converge to the best fit of the viscosity data based upon three groups of viscosity data: 1) low (0.015 to 0.025 cP) 2) mid-range (0.04 to 0.045 cP) and 3) highest (0.065 to 0.08 cP).

With data taken from References 5 and 6 and measuring the travel time, the regression constants were derived and then α and β were calculated as a function of t . Using this technique, there was a maximum of approximately 5% error in measuring any one of the viscosities of known samples at temperature and pressure.

At pressures greater than 6000 psi, there was an additional correction for pressure and temperature due to the expansion of the metal in the viscometer. For example, Figure 2 shows the trend of the uncorrected viscometer relative to literature viscosity data for methane. Departures of the apparatus are significant above 10000 psi. The following correlation was developed to correct for the error in the measured value of the viscometer (where F is the factor by which the Cambridge value is multiplied). At pressures of 20,000 psi and temperatures of 200°C (392°F), the correction factor approaches 1.7.

$$F = P \exp (7.7219 \times 10^{-5} T^2 - 1.236 \times 10^{-2} T - 10.43) + 1.0449 - 1.5838 \times 10^{-3} T \quad (4)$$

where pressure is in Psia and T is in degrees Celsius. Therefore, although there is significant empiricism involved in these measurements, as long as the results are consistent and reproducible, this may still be satisfactory.

EXPERIMENTAL PROGRAM: DENSITY

Densities were measured via a Paar densitometer up to 6000 psi (these errors are in the range of 5%). Above 6000 psi, the densities were measured gravimetrically. On the basis of repeat samples, the precision of these data was good ($\pm 1\%$). From analysis of the errors, the accuracy was:

Density (ρ) = measured mass/measured volume at pressure and temperature or:

$$\rho = \frac{\text{Mass}}{\text{Volume}} \quad (6)$$

Taking the logarithm, one has

$$\ln \rho = \ln \left(\frac{\text{mass}}{\text{vol}} \right)$$

Differentiating one arrives at

$$\frac{\partial \rho}{\rho} = \left| \frac{\partial_{\text{mass}}}{\text{mass}} \right| + \left| \frac{\partial_{\text{volume}}}{\text{volume}} \right| \quad (7)$$

Therefore, to establish the error of the gravimetric measurements, one can evaluate the first and second terms of Equation 7. Consequently, with balance maximum error of 0.1 mg and maximum pump volume error of 0.01 cc, the maximum variability of density would be, for an average 10 cc sample, at a density of 0.04 g/cc, according to Equation 7:

$$\frac{\partial \rho}{\rho} = \frac{0.0001}{0.4} + \frac{0.01}{10} = 0.00125$$

For gases used in this study, typical densities ranged from 0.04 to 0.4 and therefore the worst errors were less than 0.2%. When the densities were compared to the calculated values, using the technique of Dranchuk et al⁷, they were in close agreement throughout.

EXPERIMENTAL PROGRAM: WATER CONTENT

Water content was measured directly using a 6890 HP gas chromatograph (GC) with an HP – PlotQ capillary column (30 meter x 530 μm) with a 40 μm film thickness. Using hydrogen as a carrier gas, the injector temperature set at 175°C and the detector operating at 200°C, with a temperature ramp of 25°C per minute, all components were resolved including water. The separation of oxygen and nitrogen was not possible, but to correct for any air, if present, a separate GC was used that had a molecular sieve to facilitate that function. Using water- content reference samples prepared by commercial suppliers, the GC was calibrated.

RESULTS AND DISCUSSION

Using the equipment and procedures described above, gas data were measured with and without water content. It should be emphasized that the data presented herein are a small subset of a large experimental program, which at time of writing, has not been completed.

Gas-Phase Water Content

Using the GC methodology described, water content was measured on a base-case gas comprised of (nominal)

93, 4 and 3 mole percent methane, ethane and propane. Figure 3 shows water content that was measured at 300°F and at pressures from 513 to 20013 psia. The range was from 12.9 mole percent water to 0.92 mole percent water at 513 and 20013 psia respectively. The temperature was then increased and Figure 4 presents these data. The water content ranged from 18.94 to 2.42 mole percent, ranging from 1013 to 20013 psia at 380°F (or 31.8 down to 3.4 BBL/MMscf). In all data sets acquired by the authors to date, water content increased with temperature and with decreasing pressure. Consequently, the maximum water content will appear near the production well bore, and this water solubility may serve to desiccate the well bore region of the gas reservoir. Figure 5 shows data measured on the base gas with 10 mole percent CO₂ added. The water contents are marginally higher than in the base case but not significantly so; at the lowest common pressure (1013 psia), the difference in water content, between 0% CO₂ and 10% CO₂, was approximately 3% whereas at 15013 psia, the difference was over 20%. More data are being acquired for increasing CO₂ contents.

Gas-Phase Density

Figures 6 and 7 present the results of measured and calculated (Reference 7) gas densities at 300°F and 380°F. In Figure 8, the relative errors are compared between the calculated gas (dry) densities and the measured dry and wet gas densities. The calculated values were very close (dry gas density was measured at only one pressure, 10000 psig) to the measured dry gas densities. As the temperature increases, with concomitant increase in water content, the error between measured and calculated gas density increases; correcting the calculated values for water content should be considered as temperature rises.

Gas-Phase Viscosities

Figures 9 and 10 provide viscosities measured for dry and wet gas. At the higher temperature, the difference between the wet and dry viscosities is much greater (Figure 10). This is due to the significant increase in water-holding capacity of the gas as temperature increases. The difference between the dry and wet gases also increases as the pressure decreases. At the highest

temperature and lowest pressure, the difference in viscosity is in excess of 40% (Figure 11). This could, in some hot reservoirs, contribute to an apparent increase in skin damage due to higher actual gas-phase viscosity. The question that needs to be answered at this point is, "How much would this impact gas-well productivity?"

WELL PRODUCTIVITY

Using the standard pseudo-pressure formulation of gas flow⁹, the radial pressure profile can be calculated. Computing the radial pressure profile, using wet and dry gas viscosity and Z factors, results in a difference of approximately 1000 psi in reservoir pressure. Figure 12 shows this trend. Figure 13 shows the difference in deliverability of the well: with correct gas-phase properties included in the calculations, the rate predicted was about 20% lower than the rate predicted on the basis of a dry-gas assumption. The inclusion of wet gas properties should therefore be considered. The economic evaluation of a well can be very much influenced by the presence or absence of equilibrium water in the analysis.

Is the material balance also influenced by the presence of equilibrium water? Figure 14 shows the material balance analysis from a tight, hot gas well in Texas. The initial material balance calculations, based on the produced gas and the reported pressures, were done with dry gas properties. The extrapolated gas-in-place was 0.42 BCF. Using water-corrected properties in the analysis made very little difference. With water included, the gas-in-place extrapolated to 0.46 BCF; only 0.04 BCF difference, however, a relative change of about 10%. More material balance work on additional wells would have to be performed in order to determine whether this is a legitimate and reproducible effect. That is, there may be 10% error based upon the extrapolation. If it is reproducible, the influence of water would tend to impact gas well evaluation negatively, on the basis of flow rates, but would improve gas well economics based on total gas-in-place. More work remains to be done to better quantify these influences .

CONCLUSIONS

1. Technology is available whereby accurate gas-phase measurements can be made. The measurements made in this work were density, water content and viscosity, with and without equilibrium water.
2. More water exists in the gas phase as temperature increases and pressure decreases. Thus, water content of the gas in situ will be at a maximum near the production well-bore.
3. The presence of water in the gas phase increases density and viscosity. As much as a 40% increase in viscosity has been noted compared to dry gas viscosity.
4. This change in viscosity is responsible for as much as a 20% reduction in gas-well production rates. The influence of water content on gas-in-place is less significant than its influence on production rates.

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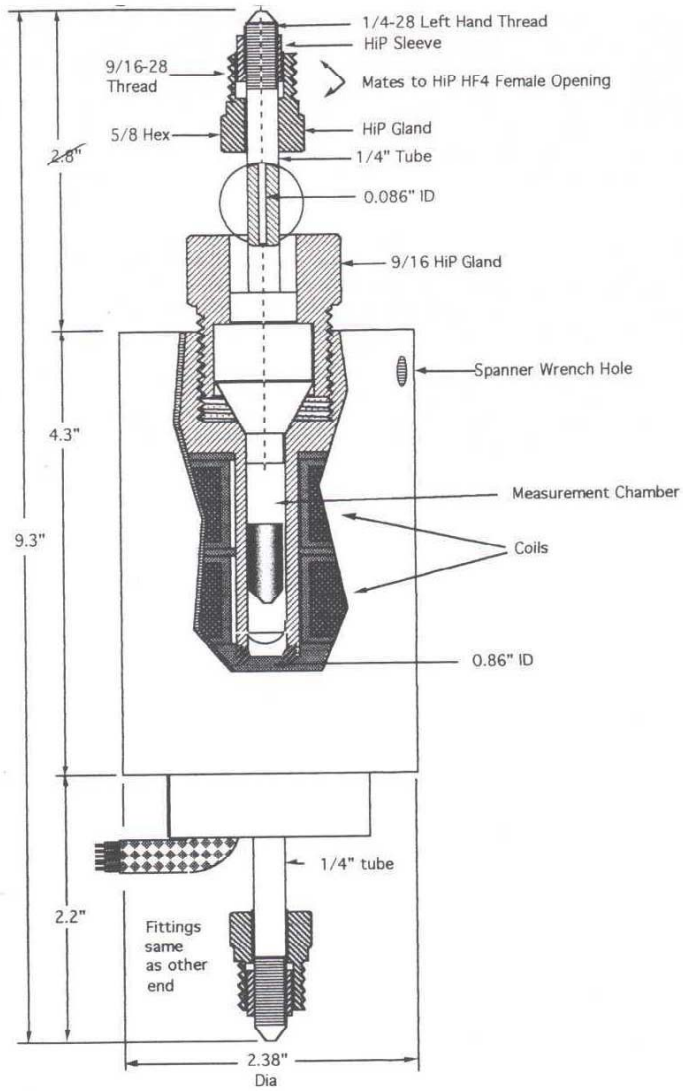


Figure 1: Viscometer Schematic

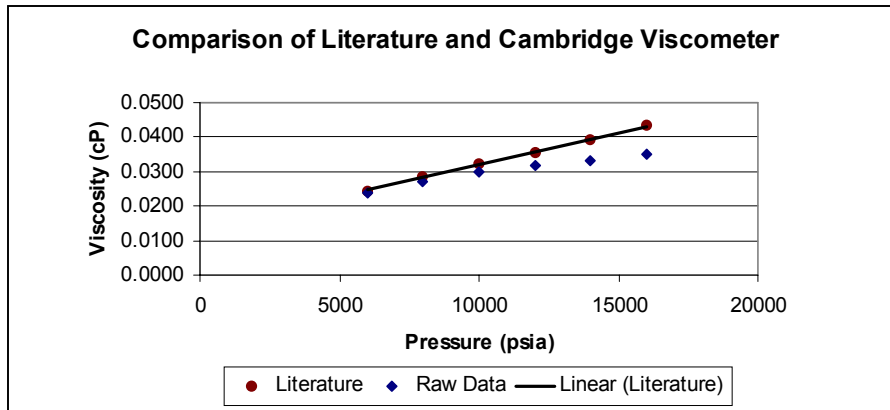


Figure 2: Uncorrected Viscosity Data

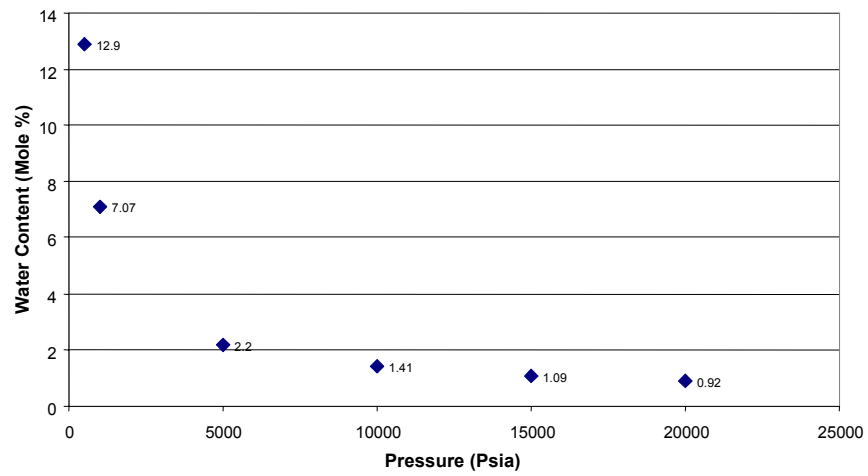


Figure 3: Base Gas-Water Content vs Pressure at 300°F

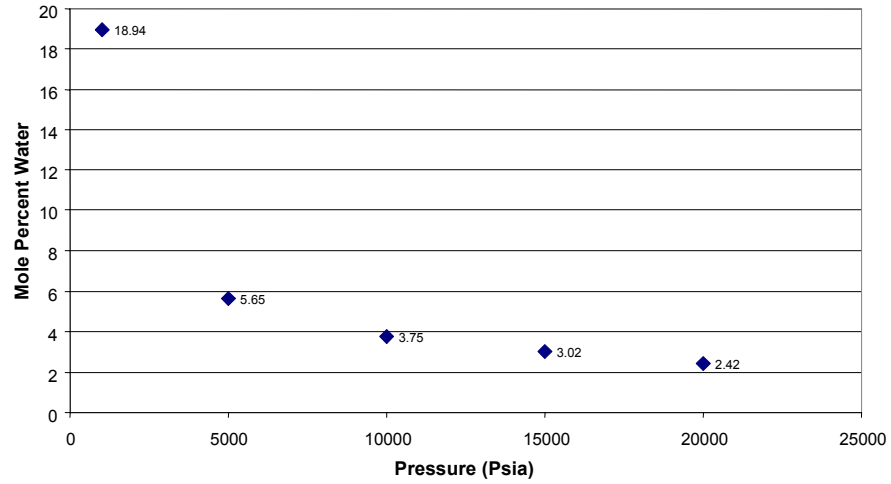


Figure 4: Water Content in Base Gas at 380°F

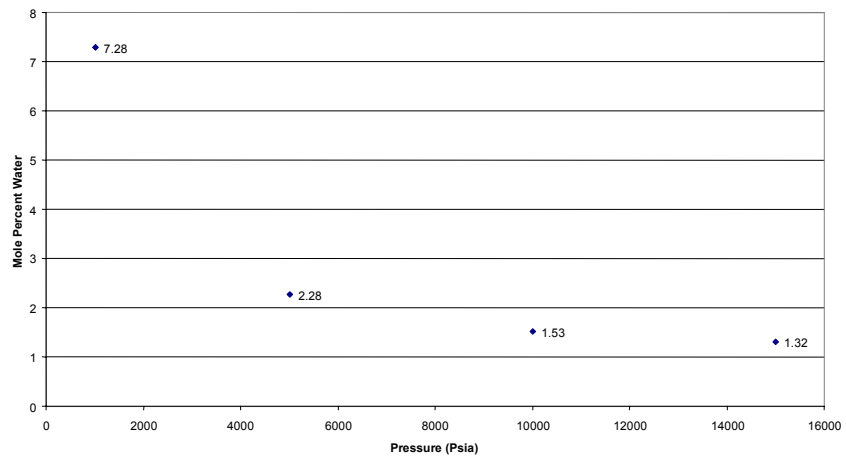


Figure 5: Water Content in Base Gas + 10% CO₂ at 300°F

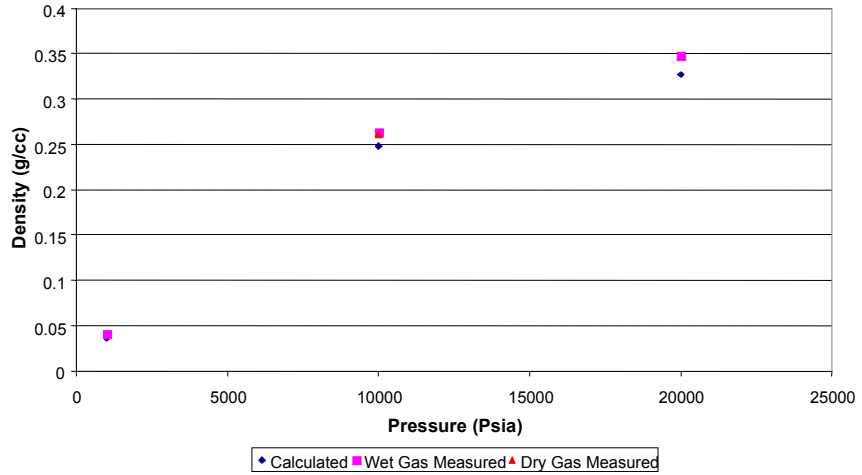


Figure 6: Wet, Dry and Calculated Gas Densities at 300°F

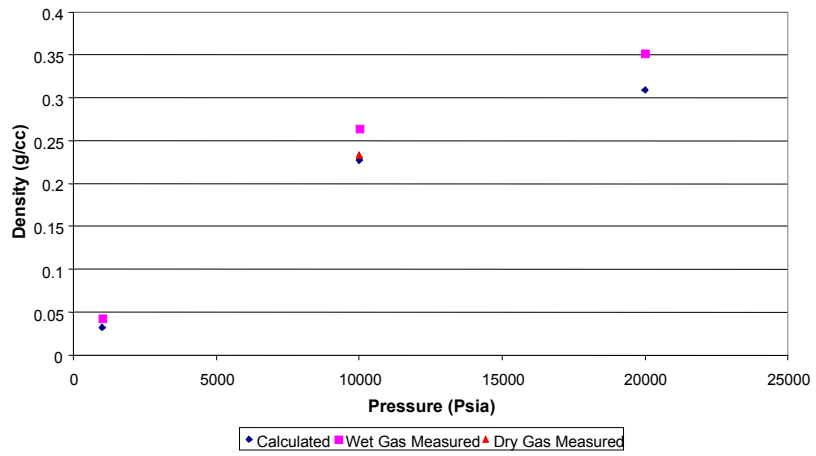


Figure 7: Wet, Dry and Calculated Gas Densities at 380°F

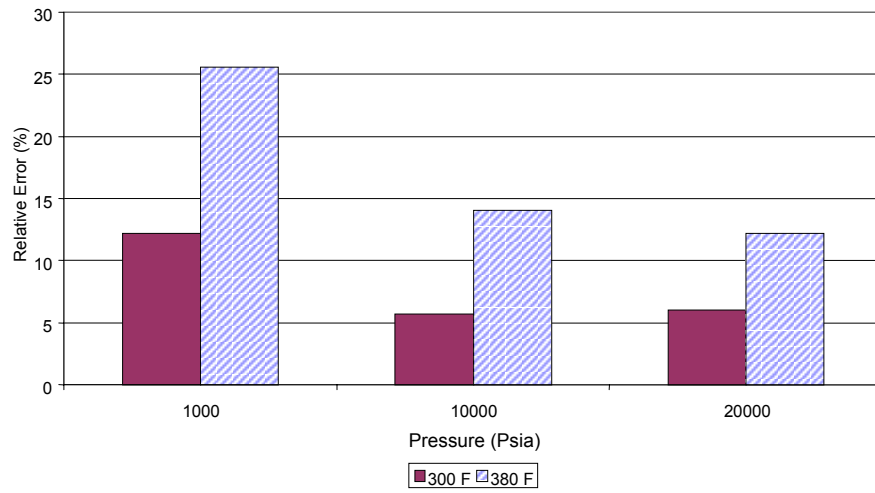


Figure 8: Relative Error – Wet Gas and Calculated Densities

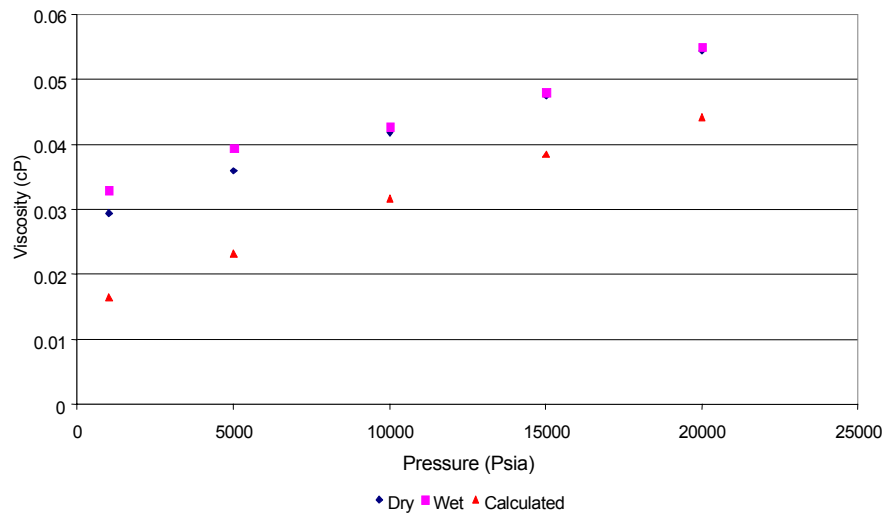


Figure 9: Dry, Wet and Calculated Viscosities at 300°F

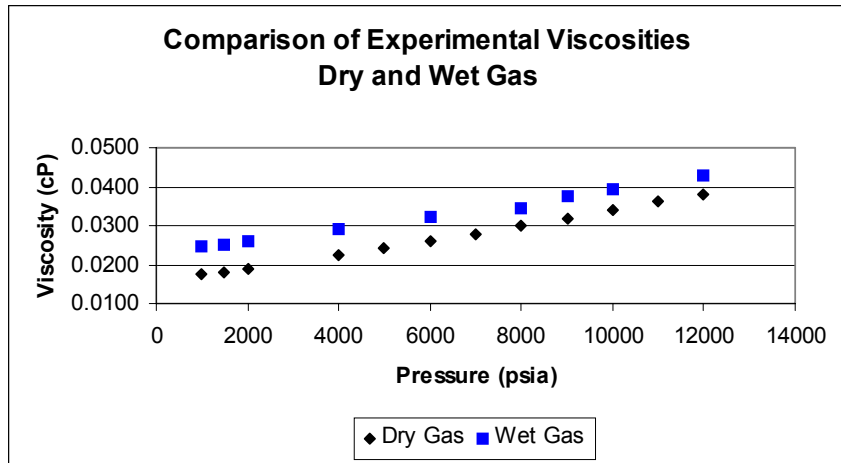


Figure 10: Viscosity Comparison

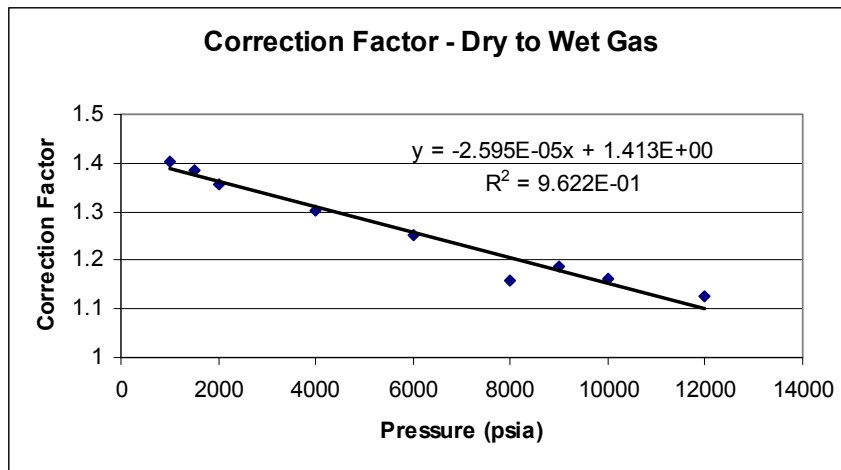


Figure 11: Viscosity Comparison

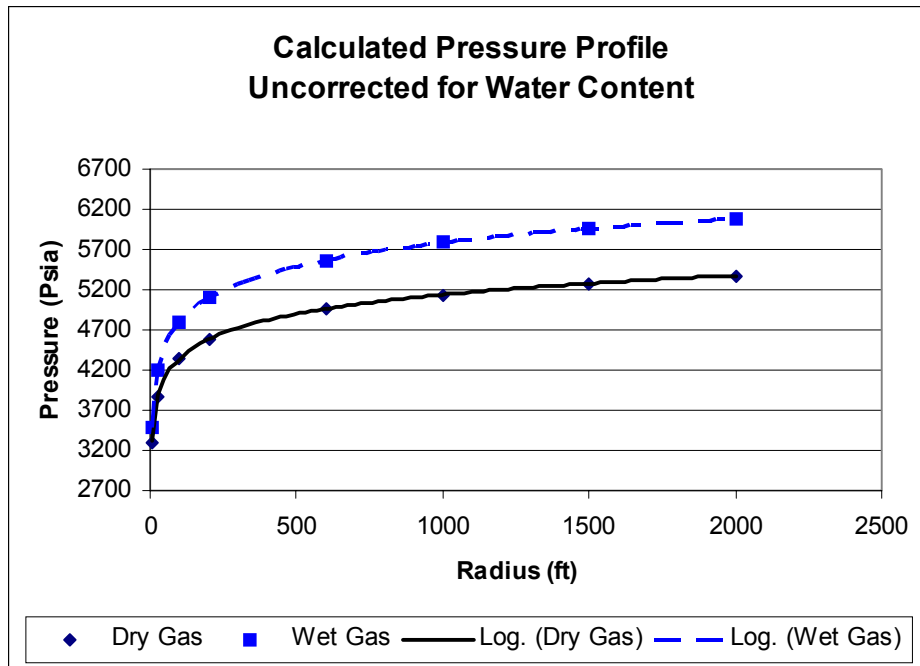


Figure 12: Effect of Water of Condensation

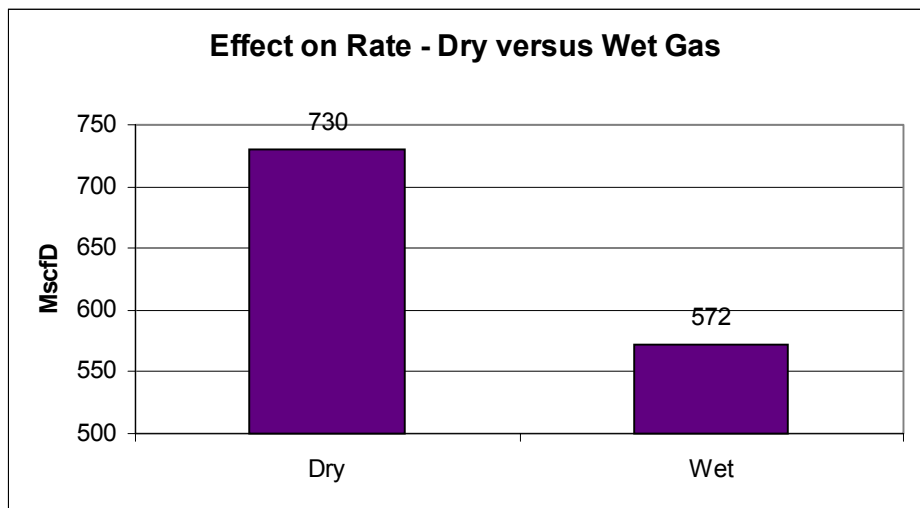


Figure 13: Predicted Well Performance

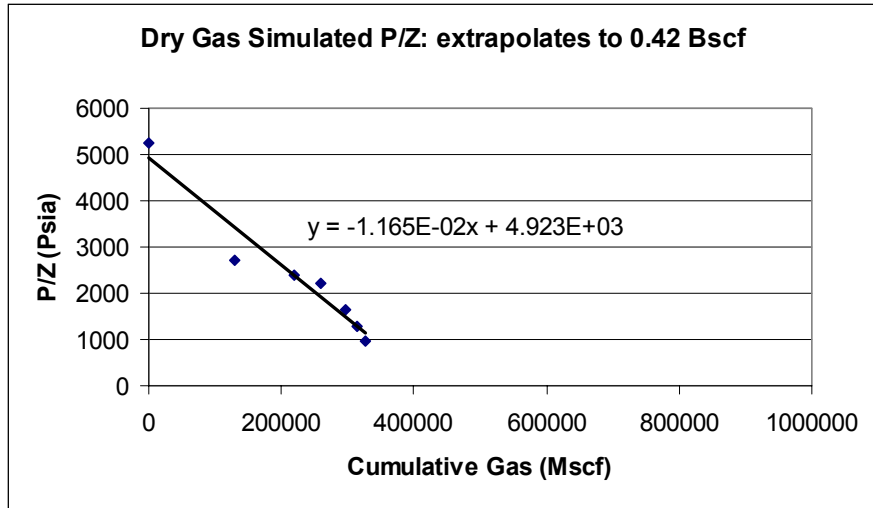


Figure 14

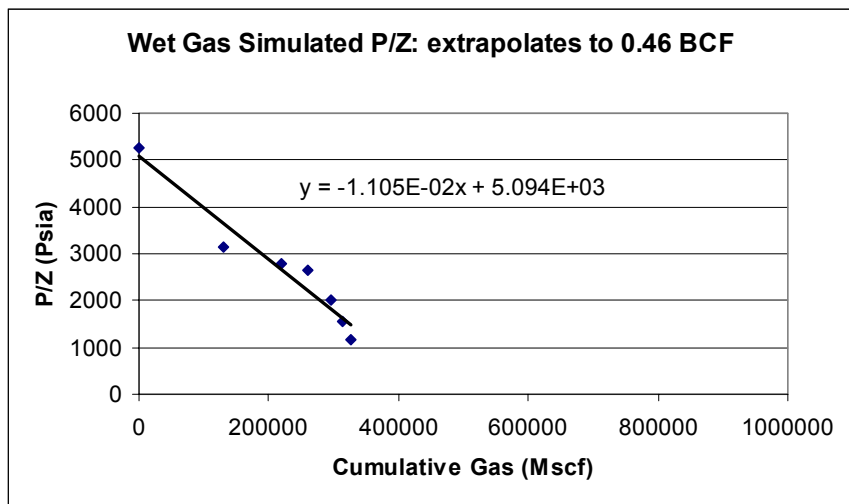


Figure 15