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## The Effect of Dissolved Gas on Reservoir Brine Viscosity

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### ABSTRACT

Correlations are available in the literature for the prediction of reservoir brine viscosity as a function of temperature, pressure, and salinity. Despite the fact that natural gas is soluble in brines, little useful data has been published regarding the effect of dissolved gas on viscosity. In the current work, the effect of dissolved methane on the viscosity of pure water has been measured at 100, 150, and 250°F, over a saturation pressure range of 0-7500 psi. The viscosity was found to increase by up to 6% with gas saturation at moderate pressures. A correlation of this data is presented, along with a recommendation for the extension of the correlation to brine/natural gas systems. In addition, a simple modification to the standard electrical contact rolling ball viscosimeter to allow its use with electrolyte solutions is described.

### INTRODUCTION

Viscosity is an important physical property influencing the flow of reservoir fluids. In most cases, oil or gas are the mobile phases. Several correlations have been published for the estimation of oil and gas viscosity. Often, however, water is the mobile phase. In this case, an accurate method for the prediction of water viscosity may be required.

Brine viscosity is known to be a function of temperature, pressure, and salinity. The specific salt ions involved also exert an influence. The most popular procedure currently in use for the estimation of brine viscosity is to obtain the viscosity of pure water at the temperature and pressure of interest, and apply a correction factor for salinity. This correction factor is termed "relative viscosity", and is the ratio of brine

viscosity to pure water viscosity at fixed temperature and pressure.

Despite the fact that methane has a known solubility in water, no data has been published regarding the effects of dissolved gas on viscosity. Rockare et al<sup>1</sup> have investigated the use of the capillary tube viscometer for the measurement of the viscosity of geopressured fluids. An attempt was made to measure the viscosity of methane saturated water. Unfortunately, their equipment was not well suited for use near saturation conditions. Their results were inconclusive.

The purpose of the current work was to determine the effect of dissolved methane on the viscosity of water. A modified RUSKA Instruments rolling ball viscosimeter was used. The results of this study indicate that viscosity is also a function of the dissolved gas/water ratio. At 100°F and 2-4000 psi, the viscosity of methane saturated water was measured to be approximately 6% greater than the viscosity of pure water. A correlation of this data, and a proposed method for the extension of this correlation to brine/natural gas systems is presented below.

### VISCOSITY OF PURE WATER

The viscosity of pure water is a function of temperature and pressure. Several investigators have studied water viscosity using a variety of methods. Among the most recent are Moszynski<sup>2</sup>, Bruges et al<sup>3</sup>, and Nagashima et al<sup>4</sup>. Numbere<sup>5</sup> has published a review of the recent data on water viscosity, and may be consulted for a more complete treatment of this subject.

Data on the viscosity of pure water may be readily found in the Steam Tables in tabular form<sup>6</sup>. A correlation for the viscosity of pure water is presented by Numbere<sup>5</sup>. (Eq. 1)

$$\mu_{\text{water}} = 0.02414 \times 10^{(247.8/(T'-140))}$$

$$x [1+4.0124 \times 10^{-8} (T-89)(p-p_{\text{sat}})]$$

.....(1)

The saturation pressure may be obtained from the steam tables, or from the correlation presented in Eq. 2 (after Keenan et al.<sup>6</sup>)

$$p_{\text{sat}} = 3203.6 \exp [-\frac{374.136 - T}{T}]$$

$$\sum_{i=1}^8 A (0.65 - 0.01T)^{i-1}$$

.....(2)

where,

$$\begin{aligned} A_1 &= -7.419242000 \\ A_2 &= -0.297210000 \\ A_3 &= -0.115528600 \\ A_4 &= -0.008685635 \\ A_5 &= 0.001094098 \\ A_6 &= 0.004399930 \\ A_7 &= 0.002520658 \\ A_8 &= 0.000521868 \end{aligned}$$

#### VISCOSITY OF BRINES

Relatively little data has been published on the viscosity of brine at elevated temperature and pressure. Korosi et al<sup>7</sup> measured the viscosities of several different binary salt solutions over a temperature range of 77-302° F, and saturation pressure. More recently, Ershagi et al<sup>8</sup> have published results of a study of geothermal brine viscosities. Numbera et al<sup>9</sup> have published a review of the subject, and have developed a correlation for relative viscosity for NaCl solutions based on Koroshi's data. Relative viscosity is defined as the ratio of brine viscosity to the viscosity of pure water, at the same temperature and pressure. This correlation is presented in Eq. 3.

$$\begin{aligned} \mu_{\text{brine}} &= \mu_{\text{water}} \{1 - 0.00187 S + 2.18 \times 10^{-5} S \\ &\quad + (T^{0.5} - 0.0135T) \\ &\quad \times [0.00276 S - 3.44 \times 10^{-4} S^{1.5}]\} \end{aligned}$$

.....(3)

In the development of Eq. 3, no data was available for the effect of pressure on brine viscosity. It is assumed that the effect of pressure on brine viscosity is the

same as on pure water. Since pressure has a very minimal effect on water viscosity, this would appear to be a safe assumption. Therefore, to obtain brine viscosity at any temperature and pressure ( $T < 572^{\circ}\text{F}$ ,  $P < 11500 \text{ psi.}$ , %NaCl<25%) the correct procedure is to calculate the viscosity of pure water at  $T$  and  $p$ , and then multiply by the relative viscosity at  $T$  and % NaCl.

#### SOLUBILITY OF METHANE IN WATER

Methane has a limited but significant solubility in water. Culberson and McKetta<sup>10</sup> have reported the solubility of methane in water over a wide range of temperature and pressure. Their results are summarized in Fig. 1. Blount et al<sup>11</sup> have studied the effect of dissolved salts on the solubility of methane in water, and have concluded that methane solubility decreases with increased solids content. A convenient correlation for a multiplicative salinity correction factor is presented in reference 12, based on the data of Dodson and Standing<sup>13</sup>. This correlation is presented below in Eq. 4.

$$\frac{R_{\text{sw}}(\text{brine})}{R_{\text{sw}}(\text{water})} = 1.0 - [0.0753 - 1.73 \times 10^{-4} T] S$$

.....(4)

#### MODIFICATION OF THE ROLLING BALL VISCOMETER

The rolling ball viscosimeter is a standard laboratory device routinely used for the measurement of viscosity at elevated temperature and pressure. (See Fig. 2) The device consists of an enclosed, inclined tube, through which a ball is allowed to roll. The velocity of the ball is directly related to the viscosity of the fluid and the buoyant forces on the ball. In practice, the velocity is determined by measuring the time required for the ball to fall a fixed distance between the electromagnetic ball release at the top of the tube and an electrical sensor at the bottom of the tube. The arrival of the ball at the bottom of the tube is indicated by the completion of a circuit between the side of the tube and a sharp electrical contact at the bottom. (See Fig. 3)

This design is configured for use with non-electrolyte fluids. With water or brine, the mechanism for sensing the arrival of the ball at the bottom of the tube is deactivated, since the circuit is completed by the fluid itself. For the purposes of this study, the viscosimeter was modified. A diaphragm and sensitive microphone were attached directly to the pin located at the bottom of the tube through the existing electrical contact port. (see Fig. 4) With the microphone and a simple amplifier, it was possible to detect the arrival of the ball by an audible click. A simple

switching circuit was designed to stop the existing viscosimeter clock upon arrival of the ball.

Many other modifications are possible which would have accomplished the same goal, and which may be more appropriate for a permanent installation. However, we found this arrangement to be quick, simple, inexpensive, and almost foolproof. A more detailed description of the modification is available from the authors upon request.

#### CALIBRATION

Several authors have published papers on the theory and operation of the rolling ball viscosimeter.<sup>14-18</sup> In particular, Hubbard and Brown<sup>17</sup> offer an excellent discussion. For stable flow regimes, viscosity is proportional to the product of density difference between the ball and fluid, and roll time (reciprocal velocity), as demonstrated in Eq. 5.

$$\mu = \alpha (\rho_{\text{ball}} - \rho_{\text{fluid}}) t_{\text{roll}} \quad \dots(5)$$

The constant  $\alpha$  is evaluated with a calibration fluid of known viscosity and density. Moreover, it is better to use several fluids of known viscosity and density similar in properties to the "unknown" fluid to provide a closer calibration in the region of interest. The calibration "plot" of viscosity versus the roll time-density difference product can then be used directly, or fit with an equation. In this study, the calibration plot was linearized, resulting in an equation of the form of Equation 6.

$$\mu = \alpha (\rho_{\text{ball}} - \rho_{\text{fluid}}) t_{\text{roll}} + \beta \quad \dots(6)$$

For this study, water and pentane were used as calibration fluids. The viscosity of water was obtained from the Steam Tables<sup>5</sup>. Water density was calculated from a correlation presented by Rowe and Chou<sup>19</sup>. Viscosity and density of pentane were obtained from Hubbard and Brown<sup>20</sup> and Starling<sup>21</sup>. The density of the ball was calculated from Eq. 7, provided by the equipment manufacturer.

$$\rho_{\text{ball}} = 7.754 - 0.000048 T \quad \dots(7)$$

In general a separate calibration is necessary for each ball/tube combination. The viscosimeter was calibrated at 100, 150, and 250°F, at pressures up to 8000 psi. The roll angle for all data was 23°. The calibration curves are presented in Figure 5.

The calibration equations are presented in Eq. 8.

For T = 100 °F or 150 °F,

$$\mu = 0.0065717 (\rho_{\text{ball}} - \rho_{\text{fluid}}) t_{\text{roll}} - 0.23128 \quad \dots\dots\dots(8a)$$

For T = 250°F,

$$\mu = 0.0045013 (\rho_{\text{ball}} - \rho_{\text{fluid}}) t_{\text{roll}} - 0.11798 \quad \dots\dots\dots(8b)$$

#### VISCOSITY MEASUREMENT

To determine the viscosity of a fluid, the roll time, fluid density, and ball density are required. The ball density was determined from Equation 7. The determination of the gas saturated water density was more complex. Dodson and Standing<sup>22</sup> studied the PVT properties of water natural gas mixtures. They reported water formation volume factors for water natural gas solutions. Given the formation volume factor, Eq. 9 was used to calculate the gas saturated water density.

$$\rho_w = \frac{0.9986 + 1.2057 \times 10^{-4} R_{sw}}{B_w} \quad \dots(9)$$

Several "runs" were made for each measurement. The average roll time was then used along with the fluid and ball densities in Eq. 8 to calculate the fluid viscosity.

#### SATURATION TECHNIQUE

All viscosity measurements were made on water at the saturation point. For each series of experiments, the viscosimeter was charged with sufficient gas to saturate the water at approximately 8000 psi. The pressure was then raised to 8000 psi by injecting water and dropped slowly by removing water from the bottom of the viscosimeter (See Fig. 6). The bubble point was observed by a change in compressibility of the system in the standard fashion.

The pressure was then lowered to 7000 psi for the first viscosity measurement. The pressure was subsequently dropped to lower pressures by water removal. At each pressure below the original bubble point, a gas phase remained in the viscosimeter. Equilibrium was obtained by rocking the cell for several days at each new pressure.

#### RESULTS AND DISCUSSION

The results of the viscosity measurements are summarized in Table 1. Fig. 7 shows the relationship between

viscosity and gas saturation pressure and  $R_{sw}$  at 100°F. The same data for 150 and 250°F are presented in Fig. 8 and 9. In general, it can be seen that the viscosity increases to nearly 6% above the value reported for pure water. The increase is somewhat greater for the 100°F case as opposed to the 150°F, and 250°F cases. This is due to the increased solubility of gas in water at 100°F. Examination of Fig. 1 shows that the gas solubility passes through a minimum at approximately 200°F. At higher temperatures, the solubility increases considerably. As our equipment had an upper operating limit of 300°F, it was not possible to obtain measurements in this high temperature region.

No data are reported specifically for the effect of dissolved natural gas on brine viscosity. These experiments are currently underway in our laboratories. However, it would be a logical approximation to assume that the presence of salt does not interfere with the effects of the gas on viscosity. Likewise, it should be acceptable to assume that the effect of gas on viscosity is not greatly affected by moderate changes in the gas composition.

Figure 10 presents a "relative viscosity" defined as gas saturated viscosity divided by pure water viscosity at the same temperature and pressure, as a function of gas saturation pressure. We recommend that this correction factor simply be applied to brine viscosity as estimated in the normal fashion. The appropriate value of  $R_{sw}$  should be determined from Culberson and McKetta<sup>10</sup> and corrected to account for the effects of salinity and natural gas gravity on solubility.

An examination of Fig. 10 shows that the viscosity rises to a value which is nearly constant at a saturation pressure of about 2000 psi. Since the overall magnitude of the correction is small in any event, it may be more expedient to make use of the "plateaued" value. At 100°F, the average value for relative viscosity becomes 1.06005. At 150°F and 250°F, the values are 1.0438 and 1.0277 respectively. These values can be correlated against temperature as indicated in Eq. 10.

$$\begin{aligned} \frac{\mu_{\text{saturated}}}{\mu_{\text{gas free}}} &= 1.109 - 5.98(10^{-4}) T \\ &\quad + 1.0933(10^{-6}) T^2 \\ &\quad \dots\dots\dots (10) \end{aligned}$$

It was anticipated that the effect of dissolved gas on viscosity would be small. The data reported in this paper support that expectation, with a maximum deviation of less than 10%. In Fig. 10, it can be seen that the change in viscosity due to gas decreases with temperature. Since the solubility of gas at 150°F is less than the solubility at 100°F, this is to be expected. However, the solubility at 250°F

is greater than the solubility at 150°F, yet the effect on viscosity is smaller. Thus it would appear that increased temperature tends to decrease the magnitude of the effect of the gas on viscosity. At considerably higher temperatures, the solubility increases significantly. The present data would suggest that the effect of gas on viscosity would continue to decrease. However, more work is needed to verify this prediction.

At the outset, it was presumed that the dissolved gas would serve to decrease the water viscosity. The increase noted in the study was unexpected. We hypothesize that this unexpected behavior is due to the highly dissimilar natures of water and methane. This behavior is similar to that encountered with emulsions.

### CONCLUSIONS

1. A standard rolling ball viscosimeter has been successfully modified for use with electrolyte solutions.
2. The viscosity of water increases by up to 5% upon saturation with methane at moderate pressures.
3. At higher temperatures, the magnitude of the effect decreases.
4. A correlation has been developed which can be used to predict the viscosity of methane saturated water, and extended for use with natural gas saturated brine.

### NOMENCLATURE

$A_1$	= constants for Eq. 2
$p$	= pressure (psi.)
$P_{\text{sat}}$	= saturation pressure (psi.)
$R_{sw}$	= gas solubility (SCF/STB)
$S$	= salinity (wt. fr. NaCl)
$t_{\text{roll}}$	= roll time (sec.)
$T$	= temperature (°F)
$T'$	= temperature (°C)
$T''$	= temperature (°K)
$\mu$	= viscosity (cp)
$\rho$	= density (g./cc.)

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TABLE 1a  
VISCOSITY DATA AT 100° F

Psat (psi)	Rsw (SCF/STB)	$\rho$ fluid (g./cc.)	Avg Roll Time (Sec)	$\mu$ (cp)	$\mu$ pure (cp)	$\mu / \mu$ pure
500	5.0	0.99397	21.0000	0.70098	0.68009	1.03072
1000	9.0	0.99515	21.3300	0.71546	0.68009	1.05201
2000	14.0	0.99712	21.4375	0.71996	0.68009	1.05862
3000	18.5	0.99906	21.4200	0.71891	0.68009	1.05708
4000	21.5	1.00082	21.4325	0.71921	0.68009	1.05753
5000	24.7	1.00331	21.4750	0.72075	0.68009	1.05979
6000	27.0	1.00429	21.4575	0.71984	0.68009	1.05844
7000	29.3	1.00598	21.6220	0.72689	0.68009	1.06881

TABLE 1b  
VISCOSITY DATA AT 150° F

Psat (psi)	Rsw (SCF/STB)	$\rho$ fluid (g./cc.)	Avg Roll Time (Sec)	$\mu$ (cp)	$\mu$ pure (cp)	$\mu / \mu$ pure
500	4.1	0.980456	14.8120	0.42736	0.42859	0.99713
1000	7.0	0.981523	14.9440	0.43311	0.42859	1.01054
2000	12.0	0.983535	15.2480	0.44642	0.43000	1.03818
3000	15.9	0.985393	15.2580	0.44668	0.43000	1.03879
4000	19.0	0.987142	15.3000	0.44837	0.43157	1.03892
5000	21.5	0.988785	15.3820	0.45184	0.43231	1.04517
6000	23.8	0.990390	15.4260	0.45364	0.43306	1.04752
7000	25.8	0.991933	15.5140	0.45739	0.43380	1.05437

TABLE 1c

VISCOSITY DATA AT 250° F

Psat (psi)	Rsw (SCF/STB)	$\rho$ fluid (g./cc.)	Avg Roll Time (Sec)	$\mu$ (cp)	$\mu$ pure (cp)	$\mu / \mu$ pure
1000	7.0	0.94425	11.5075	0.23404	0.22843	1.02457
2000	13.1	0.94639	11.6050	0.23678	0.22992	1.02983
3000	17.5	0.94831	11.6150	0.23698	0.23141	1.02405
4000	21.5	0.95014	11.7060	0.23954	0.23290	1.02849
5000	25.0	0.95189	11.7150	0.23971	0.23439	1.02269
6000	28.0	0.95355	11.7900	0.24181	0.23587	1.02519
7000	30.5	0.95511	11.8300	0.24289	0.23662	1.02653

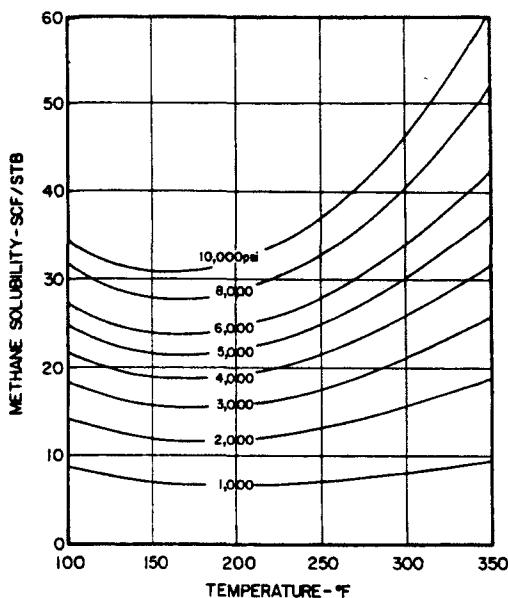


Fig. 1—Solubility of methane in water (after Culberson et al.<sup>10</sup>).

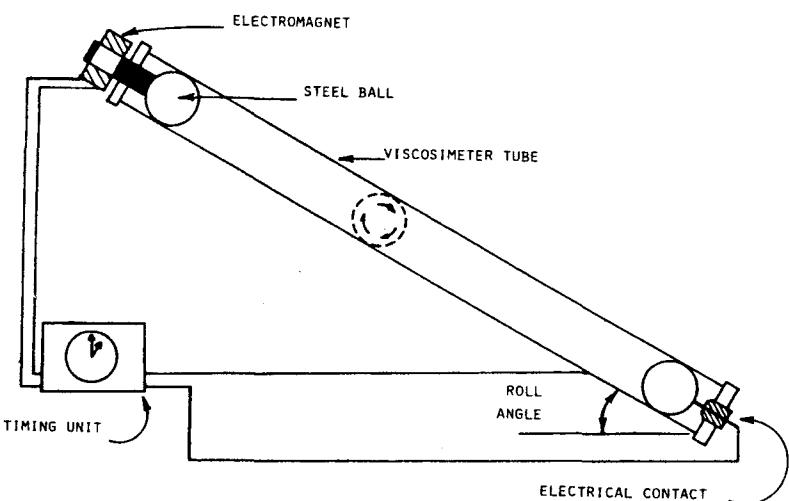


Fig. 2—Rolling ball viscosimeter.

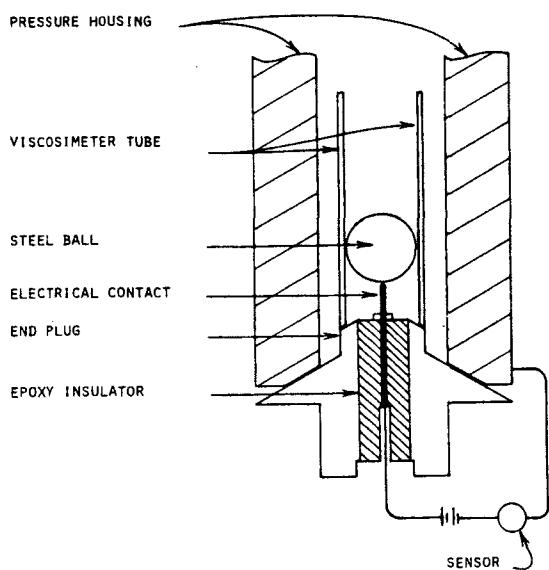


Fig. 3—Standard electrical detection system.

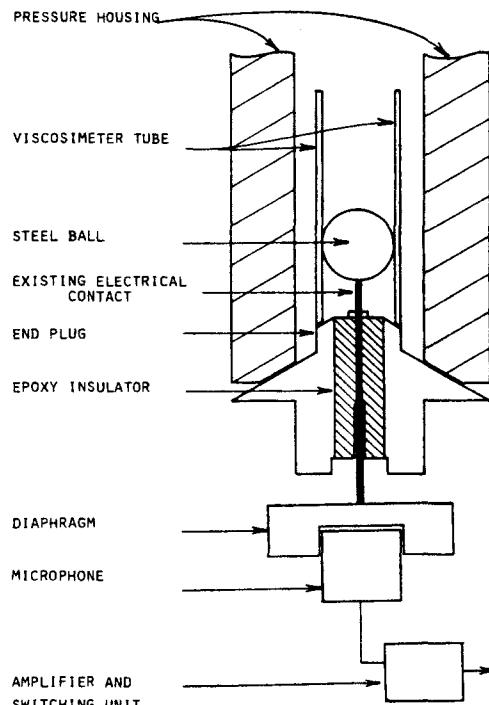


Fig. 4—Audio detection system.

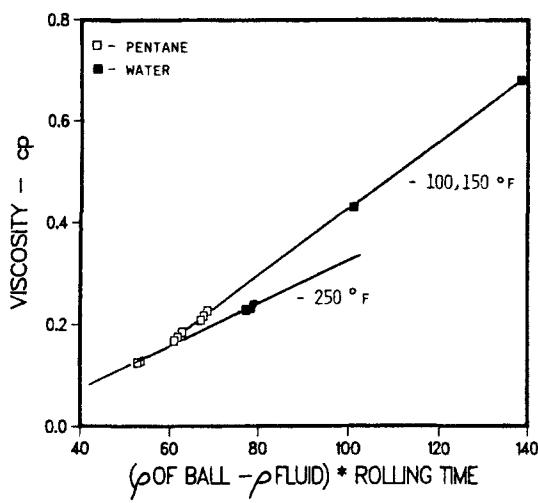


Fig. 5—Calibration curves.

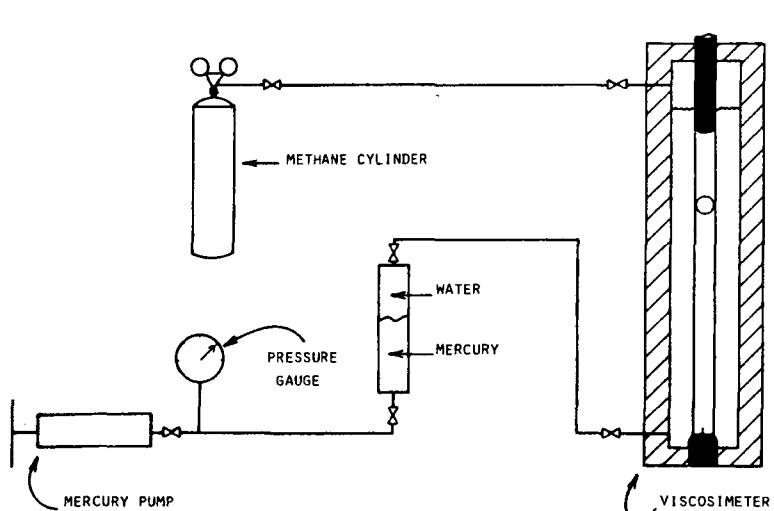


Fig. 6—Schematic of fluid transfer system.

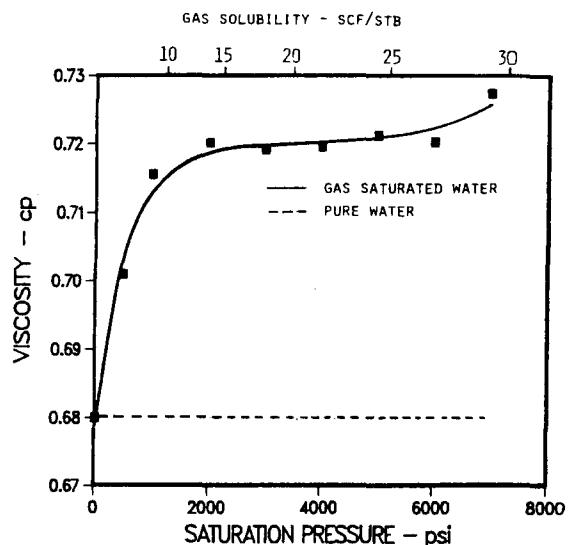


Fig. 7—Viscosity of methane-saturated water at 100°F.

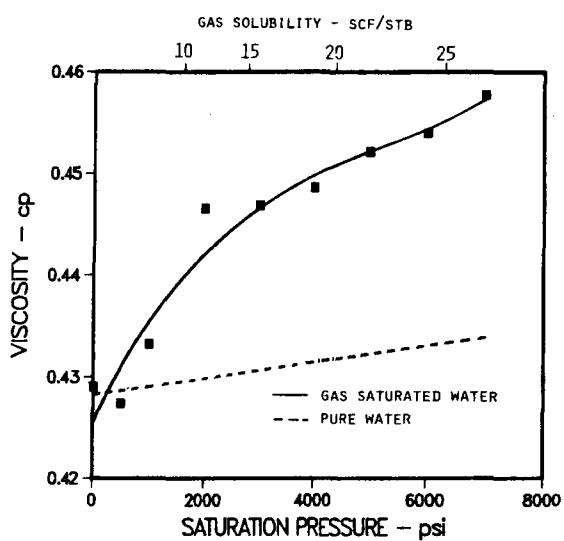


Fig. 8—Viscosity of methane-saturated water at 150°F.

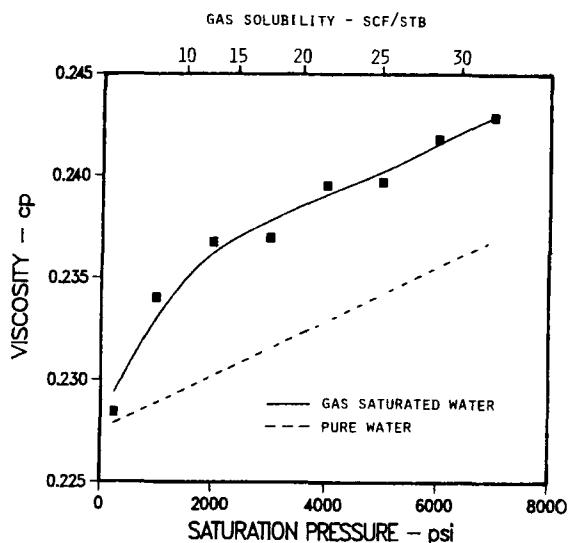


Fig. 9—Viscosity of methane-saturated water at 250°F.

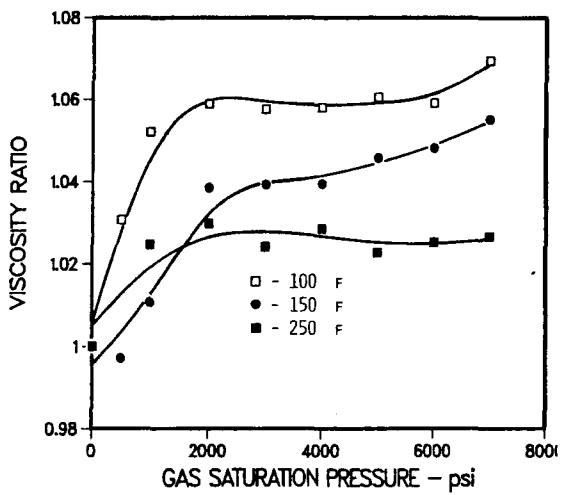


Fig. 10—Viscosity ratio.