Pressure–Volume–Temperature Correlations for Crude Oils from the Illinois Basin

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ABSTRACT

Several pressure-volume-temperature (PVT) analyses were performed using crude oil and gases from three different Illinois reservoirs. The results were used to evaluate the applicability of the commonly used correlation methods for PVT properties and to validate an equation of state (EOS) computer program that can be used to calculate PVT properties under other pressure and temperature conditions.

Knowledge of the bubble-point pressure and oil compressibility of the reservoir crude is crucial in the implementation of a successful secondary recovery program. Timely initiation of water injection can avoid poor oil recovery due to (1) excessive loss of reservoir energy and (2) creation of gas channels through excessive gas production below bubble-point pressure.

Crude oil samples from Illinois Basin reservoirs commonly contain solution gas with a composition outside the range of applicability of the methods generally used for bubble-point pressure calculations. A simple and more generally applicable equation has been derived for this purpose. This equation, which uses the pseudo critical temperature to represent the physical properties of solution gases, was found to be superior to the commonly used correlation methods for the calculation of bubble-point pressure.

The method of Vasquez and Beggs (1980) commonly used for the estimation of isothermal oil compressibility was found to be inadequate for the samples analyzed. An equation that shows better agreement with experimental values was developed. It adequately reflects the effect of pressure, temperature, and the amount of solution gas on the oil compressibilities.

Estimation of the oil formation volume factor by the method of Vasquez and Beggs (1980) and calculation of saturated oil density using the method of Katz (1942) were found to be adequate for practical purposes.

As a result of this study, Illinois Basin operators now have an improved methodology to calculate more applicable PVT properties for use in reservoir management. As more PVT data become available in the future, the full extent of the applicability of the correlations developed in this study can be established.

INTRODUCTION

Petroleum engineers require knowledge of the physical properties of petroleum fluids for various calculations relating to both reservoir and production systems. These properties must be determined at the reservoir temperature and various pressures for reservoir performance studies, and at conditions of both changing pressure and temperature for well-bore hydraulics, surface separation, and flow-line calculation. The physical properties of a representative reservoir fluid sample which is obtained either by subsurface sampling techniques or recombination of separator oil and gas, are measured with equipment for determining the pressure, volume, and temperature of the sample (PVT). The results of these analyses are used to

- estimate the volume of original oil and gas in place,
- calculate flow properties of the reservoir fluid under reservoir or pipeline conditions,
- design separator conditions for optimization of liquid recovery,
- provide information on solution gas drive energy and timing of pressure maintenance

A program of well-conditioning activities has to be undertaken to obtain the required representative sample. These activities ensure that no nonassociated free gas is being produced together with the crude oil during sampling. The program generally requires gradually reducing the production rate of a well until the ratio of produced gas to produced oil stabilizes. Shutting in the well for 1 to 2 days may be required if bottom-hole samples are needed. Most importantly, the samples must be obtained as early as possible in the production life of the reservoir to avoid changes in the overall composition of the sample.

In addition to the expense of carrying out a well-conditioning program is the $5,000 to $10,000 cost of a complete PVT analysis conducted by a petroleum service laboratory. Most independent operators have been reluctant to incur the additional expense at an early stage of reservoir development because of cash flow considerations. As an alternative, many of them rely on published PVT correlation charts to obtain the needed PVT properties for their engineering calculations. Several PVT correlation methods (Standing 1952, Lasater 1958, Vasquez and Beggs 1980) provide sufficiently accurate data for making engineering decisions in most cases. Care should be taken, however, to make sure that the oil and gas compositions of interest fall within the limits of these correlation charts or equations.

As discussed in detail later, many of these published PVT correlations are not directly applicable to reservoirs with solution gas containing a substantial amount (more than 10%) of nonhydrocarbon gas or with a gas gravity higher than 1.2. The oil composition used to construct these correlations can be quite different from that of Illinois crude oils.

To assist the independent oil and gas operators of the Illinois Basin in improving their oil recovery, the Illinois State Geological Survey (ISGS) has established a geological and engineering database from which they can draw essential information. Reservoir characterization and engineering studies of selected reservoirs are being undertaken to better understand the reservoir architecture and drive mechanism of the reservoir, and to evaluate the technologies for improved oil recovery.

When an initial attempt to obtain PVT data from the independent operators in the basin yielded only one partial PVT report from Zeigler Field and some isolated PVT data from other fields, the ISGS began a series of investigations with these objectives: (1) to provide needed PVT property data input for reservoir engineering studies, (2) to accumulate a PVT database for the Illinois Basin, (3) to evaluate the adequacy of existing PVT property correlation charts and equations for Illinois reservoir crude oils, and (4) to provide independent oil and gas producers with a more accurate method for estimating PVT relationships in cases where other published methods are found to be inadequate.

Several PVT analyses were performed using crude oil and gases from three different Illinois reservoirs. In addition, one oil swelling test with carbon dioxide was performed to evaluate the potential for CO_2 flood enhanced oil recovery from the Aux Vases Formation of the Illinois Basin.

PRESSURE–VOLUME–TEMPERATURE ANALYSES

Surface oil and gas samples collected from well sites in the fields (fig. 1) were recombined according to the known solution gas to oil ratios or saturation pressures. Whenever uncertainties existed in the actual ratio of solution gas to oil, several samples were recombined with varying gas to oil ratios. The PVT properties of these samples were then measured with the ISGS integrated PVT and capillary viscometer system. Details of the experimental procedures and calculation are described in an open file report on PVT standard operating procedures at the

Figure 1 Oil and gas sampling locations.

ISGS (Sim, in preparation). Results of the analyses of the samples are included as appendixes C, D, E and F of this report.

Nomenclature

P_b = bubble-point pressure (psi)

T_r = reservoir temperature (°F)

R_s = solution gas to oil ratio (scf/stb)

API = oil degree API

Y_g = mole fraction of gas

γ_g = gas gravity

T_{cm} = pseudo critical temperature of gas mixture

y_i = mole fraction of individual gas components

T_{ci} = critical temperature (°F) of individual gas components

P = pressure (psi)

T = temperature (°F)

C_o = oil compressibility

γ_o = oil density (gm/cm^3)

U_{os} = saturated oil viscosity (Cp)

U_{od} = gas free or dead oil viscosity (Cp)

EXISTING PRESSURE–VOLUME–TEMPERATURE CORRELATIONS: BUBBLE-POINT PRESSURES

The three most popular correlations used by the petroleum industry to calulate bubble-point pressures are those of Standing (1952), Lasater (1958), and Vasquez and Beggs (1980). The ranges of the data used to develop these PVT correlations (Beggs 1987) are summarized in table 1.

The adequacy of using these relationships for estimating the PVT properties of Illinois Basin crude oils was evaluated. Bubble-point pressures, as calculated from the PVT correlations, were compared with measured data for crude samples from the Aux Vases sandstone reservoir in three Illinois fields. Table 2 and figure 2 show the calculated results related to the measured data for wells producing from the Aux Vases Sandstone at Energy Field in Williamson County, McCullum Unit at Dale Consolidated Field in Franklin County, and Zeigler Field in Franklin County, Illinois.

Table 2 and figure 2 indicate that deviations of the calculated from the measured results are most extreme for samples from the Energy and McCullum fields. Solution gas from Energy Field contains 15% nitrogen, whereas gas from the McCullum field has a gas gravity of 1.3 because of the high content of propane and butane. They both exceed the limits of applicability of the published correlation charts.

The PVT correlations of Standing (1952) and Lasater (1958) were based on systems essentially free of nonhydrocarbon components. The presence of large amounts of nitrogen, carbon dioxide, and hydrogen sulfide result in estimated bubble points that are unrealistically low. Bubble-point pressures calculated from the Lasater correlation were adjusted upward based on anticipated errors due to the presence of nonhydrocarbon gases in the solution gases (Smith et al. 1992). As shown in table 2, however, the corrected bubble-point pressure for the Energy Field sample, which contains 15% nitrogen, is still 142 to 444 psi below the measured values. Although no information was given regarding the composition of the gas samples upon which the Vasquez and Beggs (1980) PVT correlation was based, the fact that all three PVT correlations used gas gravity to represent the properties of the solution gas limits their applicability to mixtures containing nonhydrocarbon gases.

Review of the compositions of gases produced from Illinois reservoirs, as reported by Meents (1981), reveals that a substantial number of the gases have either nitrogen contents higher than 10% or gas gravities higher than 1.2. Therefore, an

Table 1 Ranges of data used to develop PVT relationships (from published correlation charts)

	Standing	Lasater	Vasquez and Beggs
P_b (psi)	130 – 7000	48 – 5780	50 – 5250
T_r (°F)	100 – 258	82 – 272	70 – 295
R_s	20 – 1425	3 – 2905	20 – 2070
oil (API)	16.5 – 63.8	17.9 – 51.1	16 – 58
gas gravity	0.59 – .95	0.57 – 1.22	0.56 – 1.18

P_b = bubble-point pressure of the reservoir fluid (psi)
T_r = reservoir temperature (°F)
R_s = solution gas to oil ratio in standard cubic feet of gas per stock tank barrel of oil (scf/stb)
oil (API) = API gravity of stock tank oil
gas gravity = density of solution gas / density of air

Table 2 Comparison between calculated and measured bubble-point pressures

	Measured	Standing		Lasater(1)		Lasater(2)		Vasquez and Beggs	
	P psig	P psig	(ΔP) psig	P psig	(ΔP) psig	P psig	(ΔP) psig	P psig	(ΔP) psig
Energy	1600.0	1077.4	(−522)	1013.4	(−587)	1155.3	(−444)	1185.5	(−414)
Field	910.0	622.4	(−288)	674.0	(−236)	768.4	(−142)	736.0	(−174)
McCullum	350.0	728.1	(378)	622.6	(272)	628.8	(278)	800.5	(450)
Unit	150.0	558.0	(408)	483.6	(333)	488.4	(338)	611.6	(461)
Zeigler	707.0	557.5	(−150)	585.0	(−122)	643.5	(−64)	609.9	(−97)
Field	180.0	257.5	(78)	376.9	(197)	403.3	(223)	347.9	(168)

$\Delta P = P_b \text{ (calc)} - P_b \text{ (measured)}$
Standing = calculated with Standing's correlation
Lasater (1) = calculated with Lasater's correlation without correction for nonhydrocarbon gas
Lasater(2) = calculated with Lasater's correlation with correction for nonhydrocarbon gas
Vasquez and Beggs = calculated with the method of Vasquez and Beggs (1980)
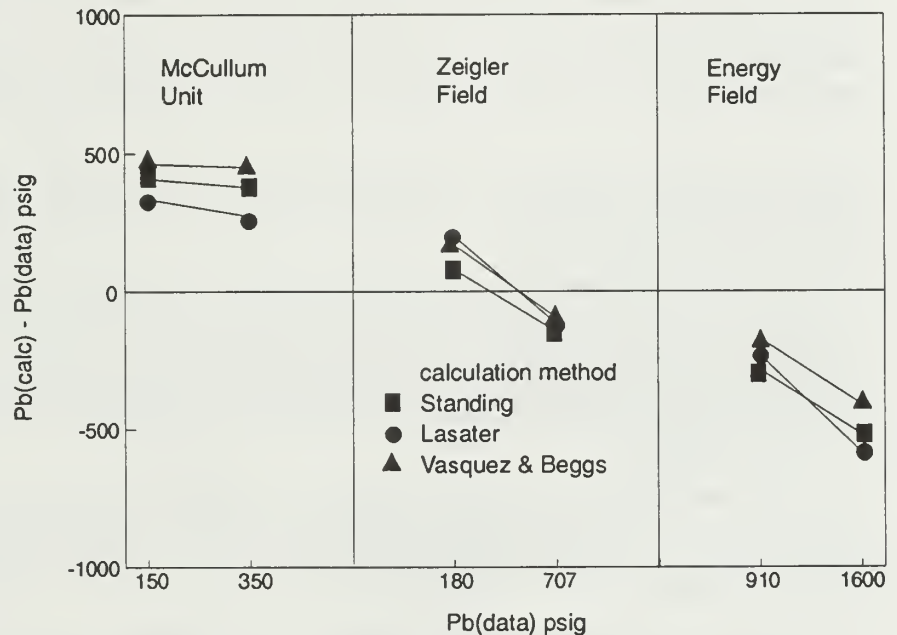
Figure 2 Comparison between bubble-point pressures

improved PVT correlation equation is needed to accurately estimate the PVT properties of Illinois reservoirs.

The equation of state (EOS) used by the petroleum industry for simulation of phase behavior and PVT properties has been discussed in several papers (e.g. Whitson 1982). Although the most important application of EOS is in the field of gas-miscible flood enhanced oil recovery, it can also be used to check the consistency of PVT and phase behavior results.

There are very limited experimental PVT data from Illinois reservoirs available for the derivation of a reliable equation for the calculation of physical properties such as bubble-point pressures, oil and gas formation volume factors, and compressibilities. Consequently, an EOS computer program was used to check the consistency

of new correlation equations and to extend the PVT relationships beyond the limits of the available data.

VALIDATION OF AN EQUATION OF STATE COMPUTER PROGRAM WITH EXPERIMENTAL DATA

The phase behavior simulator used in this work was the Western Atlas Integrated Technologies EOS-PAK[TM] licensed to the ISGS and installed on a Silicon-Graphics[TM] IRIS 4D/310GTX work station. The program includes two of the most widely used EOS: the Peng-Robinson (Peng and Robinson 1976) and the Redlich-Kwong (Redlich and Kwong 1949). Brief descriptions of them are included in appendix A.

The program contains the thermodynamic properties of the most common components in oil and gas mixtures. Thus, with the composition of the reservoir fluid as input, the program defines the relationship between the pressure, volume and temperature for a given fluid. If two of the three variables (e.g. pressure and temperature) are known, the third variable (e.g. volume) can be calculated.

Before an EOS can be used for the prediction of phase behavior, certain parameters in the equation, namely the critical properties of the oil fractions and certain interaction parameters (δ_{ij}) between the gas and the oil components, have to be determined. A common practice in the oil industry is to adjust the values of these parameters until the PVT values obtained from the EOS match a set of experimental PVT data. This process is commonly called EOS tuning.

Three sets of PVT data and one CO_2 swelling test obtained from laboratory experiments were used for the tuning process. The following summarizes the steps taken to tune the EOS program.

1) The molecular distribution of the crude oil was simulated using a computer program. Then a comparison was made between the calculated oil composition and that obtained by gas chromatographic analysis of the stock tank oil. This procedure ensures the proper distribution of hydrocarbon components. A three-fraction mixture representing the crude oil mixture was used to facilitate calculation.

2) The overall composition of the mixtures was calculated from the composition of separator gas, stock tank oil, and gas to oil ratio. The final composition was used as input for the calculation of PVT properties at specified temperatures and pressures.

3) A regression subroutine was then employed to match the experimental bubble points. In this adjustment, the interaction parameters between methane and the three oil fractions were allowed to vary 20%.

4) These calculations were followed by matching the oil formation volume factor and the oil densities. This was accomplished by adjusting the three variables, Ω_A, Ω_B and the acentric factors (ω), of the three oil fractions. (Refer to appendix A for details.)

5) Final matching of the oil viscosities was accomplished by adjusting the critical compressibility factors (Z_c) of the oil fraction.

Simulation of Pressure –Volume –Temperature Analyses

Table 3 and figure 3 compare the EOS-calculated PVT properties with the experimental data. Deviation between the calculated bubble-point pressures and the

Table 3 Comparison between measured and calculated PVT parameters for oil samples from three Illinois Basin fields

	R_s scf/stb		P_b psig			B_o rb/stb			ρ_o gm/cc		
	data	calc	data	calc	% dev	data	calc	% dev	data	calc	% dev
McCullum	319.4	312.3	350.0	342.0	0.1	1.213	1.217	−3	0.763	0.782	−5
Unit	245.0	222.0	150.0	150.0	−10	1.130	1.135	−10	0.784	0.809	−14
	0.0	0.0	0.0	0.0		1.017	1.010		0.822	0.831	
Energy	419.4	381.0	1600.0	1600.0	−10	1.187	1.163	−8		0.781	
Field	210.1	208.0	910.0	900.0	0.1	1.124	1.123	−1	0.783	0.781	−1
	65.1	60.0	100.0	100.0	−8	1.039	1.040	−8	0.795	0.811	−10
	0.0	0.0	0.0	0.0		0.017	0.010		0.821		
Zeigler	195.1	214.0	707.0	707.0	9	1.138	1.121	10	0.787	0.799	7
Field	114.6	112.0	180.0	200.0	−13	1.065	1.070	−3	0.794	0.815	−5
	0.0	0.0	0.0	0.0		1.017	1.010		0.815	0.831	

$$\% \ dev \ of \ P_b = \frac{\dfrac{P_b \ (data)}{R_s \ (data)} - \dfrac{P_b \ (calc)}{R_s \ (calc)}}{\dfrac{P_b \ (data)}{R_s \ (data)}}$$

$$\% \ dev \ of \ B_o = \frac{\dfrac{B_o \ (data)}{R_s \ (data)} - \dfrac{B_o \ (calc)}{R_s \ (calc)}}{\dfrac{B_o \ (data)}{R_s \ (data)}}$$

data = experimental data measured with the ISGS PVT equipment
calc = EOS (equation of state) calculated results
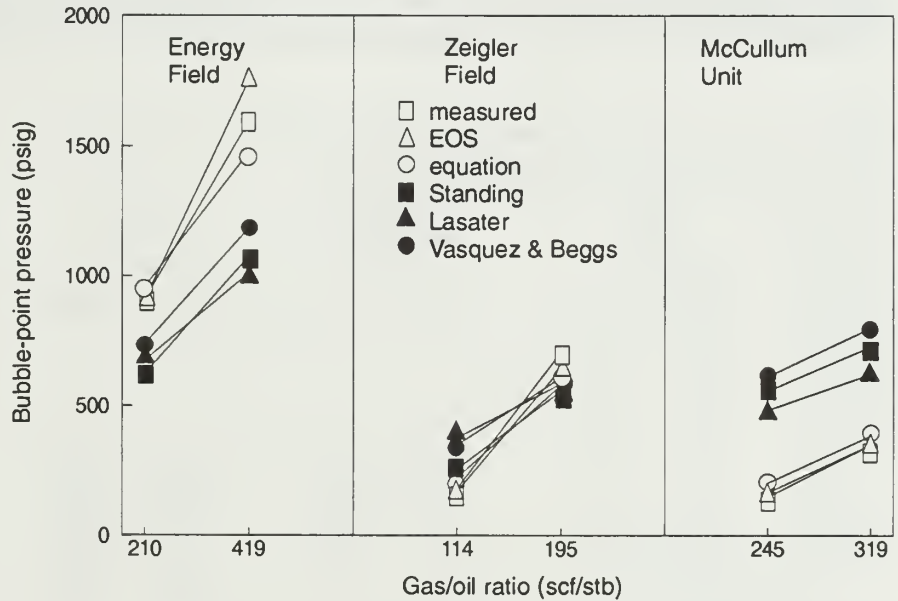
Figure 3 Bubble-point matching with EOS (calculated versus measured)

experimental bubble-point values ranges from 1% to 13%, with an average deviation of 4.8%. Deviation between calculated oil formation volume factors and experimental values ranges from 0.1% to 10%, with an average deviation of 3.2%.

The overall composition of the four reservoir samples used for tuning and the thermodynamic properties of the three pseudo fractions used to represent the crude oils are tabulated in appendix B. Detailed results of the simulation, such as the comparison of calculated and measured gas compositions, are also included in appendix B.

Simulation of Carbon Dioxide Swelling Tests

Once the EOS program was adjusted to mimic the PVT experimental data, the phase behavior of these reservoir crude oils in the presence of CO_2 was calculated. In a predictive mode, the calculation is performed without altering the values of the thermodynamic parameters of the oil and gas components.

The results presented in table 4 and figure 4 show the ability of the tuned EOS to simulate the results of a CO_2 swelling test performed on the crude oil from McCullum Unit at Dale Consolidated Field in Franklin County. In the plot of saturation pressure relative to gas to oil ratio (GOR) (fig.4), the experimental data show a critical point at about 1200 psig, where a further increase in pressure does not result in further CO_2 dissolution. Because this critical point of the mixture is highly dependent upon the oil composition, the ability of the EOS to accurately estimate the critical point suggests that the real oil mixtures are reasonably well simulated by the three pseudo fractions.

NEW CORRELATIONS

One of the objectives of this study was to provide Illinois Basin producers with a means of calculating essential PVT properties from more readily measurable physical properties such as oil API, gas composition, and gas to oil ratios. Although a tuned EOS program is a good vehicle for performing these tasks, not many independent operators have access to these types of computer programs. Thus, several correlation equations, based both on experimental data and on properties calculated from the tuned EOS program, have been derived for use in the basin.

Table 4 Comparison between measured and calculated PVT parameters for a CO_2 swelling test of oil from Dale Consolidated Field

Saturation pressure (psig)	Gas/oil ratio (scf/stb)		Oil formation volume factor (rb/stb)		Oil density (gm/cc)	
	calc	data	calc	data	calc	data
3300	1321					
3000	1280	1214				
2500	1250	1214				
2000	1210	1214				
1400	1175	1214	1.388	1.478	0.879	0.847
1200	1066	1180	1.366	1.477	0.862	0.847
1000	828	860	1.318	1.370	0.858	0.838
800	608	642	1.240	1.268	0.854	0.824
400	272	233	1.121	1.116	0.844	0.813
0	0	0	1.0	1.0	0.843	0.820

data = experimental results obtained with ISGS PVT equipment
calc = results calculated with EOS
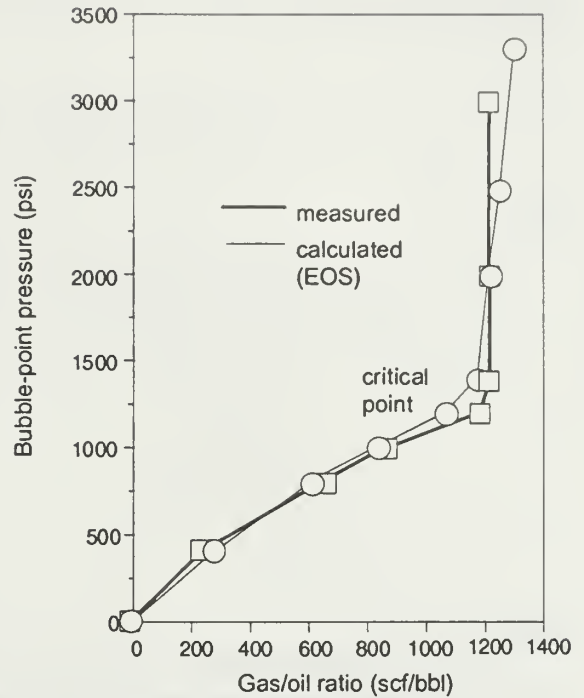
Figure 4 Oil swelling test with CO_2.

Bubble-Point Pressure Correlation

A better prediction of the saturation pressure of mixtures that have nitrogen contents higher than 10% or gas gravities higher than 1.2 required a different approach from that of the three previous correlations. The pseudo critical temperature of the solution gas, instead of the gas gravity, was used to represent the solution gas properties. Figure 5 shows a plot of the measured bubble-point pressure relative to a function containing the mole fraction of the gas and the pseudo critical temperature of the gas mixture. The slope of the best fit line determined by least square method
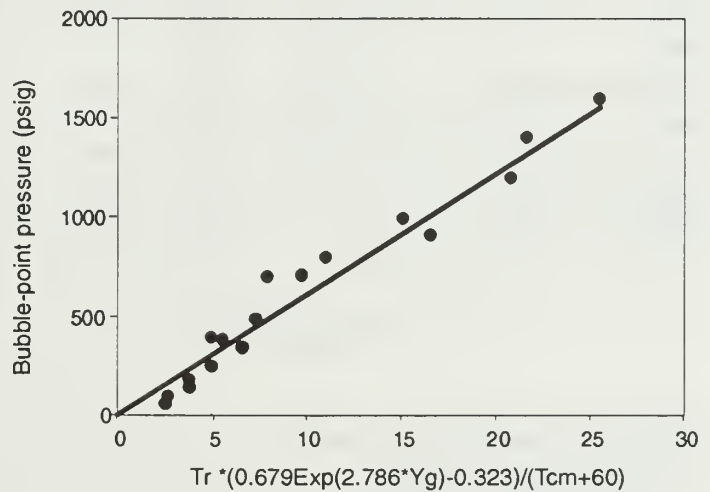
Figure 5 Bubble-point pressure relative to critical temperature of gas.

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is 65.23, and thus the bubble point pressure of the mixture can be obtained from the following equation:

$$P_b = 65.23 T_r \frac{0.679 Exp \, (2.786 Y_g) - 0.323}{T_{cm} + 60} \qquad [1]$$

where
P_b = bubble-point pressure (psi)
Y_g = mole fraction of gas (calculated from solution gas to oil ratio, molecular weight of oil, and oil density)
T_{cm} = pseudo critical temperature of the solution gas (°F)

$$Y_g = \frac{\dfrac{R_s}{379.3}}{\dfrac{R_s}{379.3} + \dfrac{350\gamma_o}{M_o}} \qquad [2]$$

$$T_{cm} = \Sigma y_i T_{ci} \qquad [3]$$

where
T_{cm} = pseudo critical temperature of the solution gas (°F)
y_i = mole fraction of individual gas components
M_o = molecular weight of stock tank oil
R_s = solution gas oil ratio (scf/stb)
T_{ci} = critical temperature of gas components (°F)
T_r = reservoir temperature (°R)
γ_o = oil density (gm/cc)

Table 5 Calculation of bubble-point pressures

	R_s	T_{cm}	Data P_b	Equation 1 P_b	% dev	EOS P_b	% dev
Energy	419	−13.6	1600.0	1480.3	−8	1759.6	10
Field	210	−18.7	910.0	957.0	5	908.6	−0.2
McCullum	319	83.1	350.0	384.6	10	349.8	−0.1
Unit	292	117.4	250.0	289.8	16	252.4	1
	245	140.0	150.0	204.3	36	165.5	10
Zeigler	195	12.17	707	580.4	−18	645.0	−9
Field	184	57.7	388	342.6	−12	401.1	3
	114	72.2	180	223.2	24	167.9	−7

$$\% \, dev = \frac{P_b \, (calc) - P_b \, (data)}{P_b \, (data)}$$

data = experimental results
Equation 1 = calculated results using equation 1
EOS = calculated results with EOS
R_s = solution gas to oil ratio (scf/stb)
T_{cm} = critical temperature of gas mixture (°F)
P_b = bubble-point pressure (psig)

Table 6 Prediction of bubble-point pressures at 150°F

	R_s scf/stb	EOS P_b psi	Eq'n 1 P_b psi	% dev	Standing P_b psi	% dev	Lasater P_b psi	% dev	Vasquez and Beggs P_b psi	% dev
Energy	419	1853.6	1659.9	−10	1236.7	−33	1136.4	−39	1375.1	−26
Field	210	1152.5	1077.9	−7	718.7	−38	693.6	−40	792.6	−31
	166	556.6	379.8	−32	539.3	−3	538.3	−3	592.3	6
	65	108.5	148.4	36	219.5	82	293.7	170	215.3	98
McCullum	319	540.0	430.7	−20	812.0	50	720.5	33	897.1	66
Unit	292	370.0	324.2	−12	753.1	104	670.8	81	831.1	124
	245	254.2	252.3	−1	623.0	145	557.2	119	685.6	169
Zeigler	195	820.6	637.9	−22	625.6	−24	643.0	−22	657.4	−20
Field	184	491.2	377.2	−23	574.3	17	611.8	25	533.5	9
	114	261.2	249.1	−5	385.4	48	427.0	64	421.1	61

$$\% \; dev = \frac{P_b \, (correlation) - P_b \, (EOS)}{P_b \, (EOS)}$$

P_b (correlation) = calculated by the various correlations
P_b (EOS) = calculated by the tuned equation of state program

Bubble-point values calculated with this equation can be compared with the values from the EOS method (table 5). An example of the calculation is included in appendix G. This simple correlation provides substantial improvement over the Standing (1952), Lasater (1958), and Vasquez and Beggs (1980) methods in cases where the nitrogen, propane, or butane contents are high in the solution gases. Before this equation can be used, the composition of the solution gas must be analyzed. The pseudo critical temperature of the solution gas mixture can then be calculated with equation 3.

Table 6 compares the bubble-point pressures calculated with equation 1 at 150°F with those predicted by the tuned EOS program and the three published correlation methods. It shows that the bubble points predicted by equation 1 or by the tuned EOS do not change significantly with temperature. Thus, in the absence of an EOS program, equation 1 can be used for prediction of the bubble-point pressure of crude oil with temperatures up to 150°F.

Calculation of Oil Formation Volume Factors of Saturated Oil

Table 7 compares measured values for the saturated oil formation volume factor with calculated values obtained with either the Standing (1952) or the Vasquez and Beggs (1980) method. It shows that Vasquez and Beggs provide a reasonable estimate of the saturated oil formation volume factors even when the content of nonhydrocarbon gas is high, as in the case of the CO_2 swelling tests. The Standing (1952) method substantially overestimates the oil swelling by CO_2.

Calculation of Isothermal Compressibility of Undersaturated Oil

Measurements of oil compressibility at pressures above the saturation pressure of the reservoir fluid are part of the PVT analysis; they provide data essential for evaluating the driving force during primary depletion from the original pressure of the reservoir down to the bubble-point pressure of the reservoir crude.

Table 7 Calculation of oil formation volume factor

	P_b	B_o Measured	B_o Standing calc	% dev	B_o Vasquez and Beggs calc	% dev	B_o EOS calc	% dev
Energy	1600	1.187	1.227	3.3	1.206	1.6	1.163	–2
Field	910	1.124	1.107	–2	1.107	–1.5	1.123	–0.1
	400	1.072	1.076	0.4	1.086	1.4	1.071	–0.1
	100	1.039	1.037	–0.2	1.036	–0.3	1.040	0.1
McCullum	350	1.213	1.201	–1	1.161	–4.3	1.217	0.3
Unit	250	1.190	1.187	–0.3	1.151	–3	1.150	–0.4
	150	1.130	1.158	2.5	1.126	–0.3	1.135	0.4
	65	1.069	1.074	0.5	1.060	0.8	1.070	0.1
Zeigler	707	1.138	1.111	–1.6	1.105	–2.9	1.121	–1
Field	388	1.100	1.113	1	1.083	–1.5	1.099	–0.1
	180	1.065	1.072	0.7	1.067	0.2	1.070	0.5

Swelling test of McCullum crude with CO_2

P_b	R_s							
1400	1214	1.478	1.926	30	1.579	7	1.388	–6
1200	1180	1.477	1.897	28	1.563	6	1.366	–7
1000	860	1.370	1.630	19	1.413	3	1.318	–4
800	642	1.268	1.456	15	1.311	3	1.240	–2
400	233	1.116	1.158	4	1.119	0.3	1.121	0.4

$$\% \; dev = \frac{B_o \, (calc) - B_o \, (data)}{B_o \, (data)}$$

Table 8 lists oil compressibility factors measured at various solution gas to oil ratios and reservoir pressure conditions. Using the Vasquez and Beggs (1980) correlation equation to calculate undersaturated oil compressibility does not provide an accurate estimation. Correlation equation 4 was based on the data obtained experimentally and calculated with EOS.

$$C_o = (Exp(1.85 + 0.0043(T - 84) - 0.0001122P) + R_s Exp(-3.7 - 0.00074P))10^{-6} \qquad [4]$$

where

R_s = solution gas to oil ratio (scf/stb)
P = pressure of interest (psi)
T = reservoir temperature (°F)

Viscosity Relationships

Two methods are commonly used to calculate the viscosity of a gas-saturated crude oils. Chew and Connally (1959) obtained gas-saturated viscosity values as follows:

$$U_{os} = aU^b_{od} \qquad [5]$$

where

U_{os} = saturated oil viscosity (Cp)
U_{od} = gas free or dead oil viscosity (Cp)
a and b = function of solution gas to oil ratio obtained graphically

Beggs and Robinson (1975) obtained similar values from the following relationship:

Table 8 Comparison between values for undersaturated oil compressibility calculated by the methods of Vasquez and Beggs (1980) and equation 4

| | Rs (scf/stb) | γ_g | T (°F) | API | P (psi) | Measured psi^{-1} | Compressibility (C_o) Calculated | | | |
| | | | | | | | Vasquez and Beggs | | Equation 4 | |
							psi^{-1}	% dev	psi^{-1}	% dev
Energy	419	1.038	84	38	2000	7.7E-6	6.74E-6	13	7.44E-6	3
Field	210	1.001	84	38	1000	8.0E-6	3.41E-6	57	8.15E-6	–2
	210	1.001	84	38	2000	6.7E-6	3.85E-6	42	6.26E-6	6
Zeigler	198	1.098	95	38	1000	8.5E-6	3.80E-6	55	8.29E-6	2
Field	198	1.098	95	38	2000	6.8E-6	1.90E-6	72	6.45E-6	5
	124	1.109	95	38	1000	6.8E-6	1.66E-6	76	7.47E-6	–9
	124	1.109	95	38	2000	5.8E-6	8.30E-7	43	6.03E-6	–4
McCullum	319	1.312	98	37	1000	9.6E-6	7.66E-6	20	9.80E-6	–2
Unit	319	1.312	98	37	2000	7.3E-6	3.83E-6	47	7.19E-6	1
	113	1.310	98	37	1000	7.4E-6	5.00E-6	32	7.37E-6	1
	113	1.310	98	37	2000	5.5E-6	2.50E-6	54	6.04E-6	–9

$$\% \ dev = \frac{C_o \ (data) - C_o \ (calc)}{C_o \ (data)}$$

$$U_{os} = AU_{od}{}^{B} \qquad\qquad [6]$$

where

$$A = 10.715(Rs + 100)^{-0.515}$$
$$B = 5.44(Rs + 150)^{-0.338}$$

Both of these equations give reasonable values for the gas-saturated viscosity, if the dead-oil viscosity at the temperature of interest is known. Table 9 compares values for gas-saturated viscosity obtained experimentally with those calculated by equations 5 and 6.

The calculated results from the Beggs and Robinson (1975) method are better than those from the Chew and Connally (1959) method applied to all three crude oils measured for this study. The EOS-PAK™ program incorporates the Lohrenz, Bray, and Clark (1964) relationship for the calculation of oil viscosity (table 9). Calculation using this method requires knowledge of the critical volumes and densities of the mixture. A regression subroutine was used to match the viscosities of the gas-free oil at reservoir temperature. When this method was used, the calculated saturated viscosities were consistently higher than the measured values. (It is beyond the scope of this study to investigate the cause of this deviation.) When the EOS was tuned by matching the viscosity of gas-saturated oil, however, the calculated viscosities matched the experimental data rather closely. Thus, it is recommended that the experimental viscosity of saturated oil be used for tuning of the EOS.

Correlation of Saturated Oil Densities

Values for the density of gas-saturated reservoir crude oil at various pressures at the reservoir temperature are required for engineering calculations. The method of Katz (1942) estimates live-oil density from oil API gravity, gas gravity, and the gas to oil ratio. The calculated values using this method are compared with the measured results in table 10. In general, the agreement is good within the range of pressure

Table 9 Calculation of saturated oil viscosity

| | P_b | R_s | U_{os} (Measured) | U_{os} (Calculated) | | | | | | | |
| | | | | Chew and Connally | | Beggs and Robinson | | EOS (1) | | EOS (2) | |
	psig	scf/stb	Cp	Cp	% dev	Cp	% dev	Cp	% dev	Cp	% dev
Energy	910	210	1.55	2.08	34	1.58	2	2.67	72	1.62	4
Field	400	166	1.80	2.32	28	1.79	−1	3.18	77	1.91	6
	100	65	2.31	3.14	35	2.66	15	3.74	62	2.17	−6
	0	0	4.06	4.06		4.06		4.06		2.35	−42
Zeigler	707	195	1.88	2.36	25	1.74	−7	2.77	47	1.80	−4
Field	180	114	2.19	2.83	29	2.27	4	3.53	62	2.08	−5
	0	0	4.40	4.40		4.40		4.40		2.52	−42
McCullum	350	319	1.39	1.77	27	1.20	−14	2.63	89	1.41	1
Unit	150	245	2.33	2.32	1	1.71	−26	3.18	36	1.65	−29
	65	164	2.44	3.07	26	2.45	1	3.72	52	1.90	−22
	0	0	4.55	4.55		4.55		4.45		2.25	−50

$$\% \; dev = \frac{U_{os} \, (calc) - U_{os} \, (data)}{U_{os} \, (data)}$$

R_s = solution gas oil ratio (scf/stb)
EOS(1) = EOS calculated results by matching gas-free crude oil
EOS(2) = EOS calculated results by matching viscosity of gas-saturated oil

Table 10 Calculation of saturated oil density by the method of Katz (1942)

| | P | T | R_s | Oil density (gm/cc) | | |
| | | | | | Gas-saturated | |
	psig	°F	scf/stb	Gas-free	calculated	measured
McCullum	350	98	319	0.83	0.756	0.763
Unit	150	98	245	0.83	0.792	0.773
	65	98	164	0.83	0.814	0.795
Energy	910	84	210	0.83	0.785	0.783
Field	100	84	65	0.83	0.811	0.795
Zeigler	707	95	195	0.83	0.781	0.787
Field	180	95	114	0.83	0.804	0.794

Measured = experimental results measured with ISGS PVT equipment

and gas to oil ratio under investigation. Thus, no attempt was made to construct a different correlation method.

SUMMARY

Illinois crude oil samples frequently contain solution gas that has a nonhydrocarbon content higher than 10% and gravities higher than 1.2. The samples are thus outside the range of applicability of the commonly used methods for estimating bubble-point pressures. A simple equation (1) that agrees with both the limited PVT data and the calculated results of a tuned EOS has been derived for these types of crude oils.

The method of Vasquez and Beggs (1980) commonly used for the estimation of isothermal oil compressibility has been found to be inadequate for the samples analyzed. An equation (4) that shows better agreement with experimental values was developed. For the estimation of saturated oil formation volume factors, the Vasquez and Beggs method (1980) was found to be adequate. The relationship derived by Standing (1952) consistently overestimates oil swelling by CO_2 for crude oil from the Aux Vases Formation in the Illinois Basin.

Values for saturated oil viscosity estimated, on the basis of the Beggs and Robinson (1975) method, from the viscosity of gas-free crude oil were found to be closer to experimental values than those based on the Chew and Connally (1959) equation.

Values for gas-saturated oil density calculated using the Katz (1942) method agreed closely with experimental determined values.

Further PVT experiments are needed to define the limits of applicability of equations 1 and 4.

ACKNOWLEDGMENTS

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APPENDIX A   TWO EQUATIONS OF STATE

Redlich and Kwong (1949) equation of state

$$P = \frac{RT}{V-b} - \frac{aT^{-0.5}}{V(V+b)}$$

where

$$a = 0.4278 \frac{R^2 T_c^{2.5}}{P_c}$$

$$b = 0.0867 \frac{RT_c}{P_c}$$

P_c = critical pressure
T_c = critical temperature

The Peng and Robinson (1976) equation of state

$$P = \frac{RT}{V-b} - \frac{a(T)}{V(V+b)+b(V-b)}$$

where

$$b = 0.07780 \frac{RT_c}{P_c}$$

$$a(T) = (T_c)\, \alpha\, (T_R, \omega)$$

$$\alpha^{\frac{1}{2}}(T_R) = 1 + \kappa\,(1 - T_R^{0.5})$$

$$\kappa = 0.37464 + 1.54226\omega - 0.26992\omega^2$$

where

ω = acentric factor
P_c = critical pressure
T_c = critical temperature

For determination of a and b of mixtures

$$a_m = \Sigma_i \Sigma_j\ x_i x_j\ a_{ij}$$
$$b_m = \Sigma\ x_i\ b_i$$

$$a_{ij} = (1 - \delta_{ij})\ \sqrt{a_i a_j}$$

where

δ_{ij} = interaction parameter between component i and j

For Redlich-Kwong EOS Ω_A = 0.4278 and Ω_B = 0.0867 and in Peng-Robinson EOS Ω_A = 0.45724 and Ω_B = 0.0778

During the tuning of the equation of state program, the constants Ω_A and Ω_B for the pseudo-fractions are sometimes altered in order to match the experimental data.

APPENDIX B   INPUT DATA AND RESULTS OF EOS MATCHING

Table B-1   Composition of reservoir fluid samples

	Zeigler	McCullum	Energy sample 1	Energy sample 2
N_2	2.61	0.70	5.29	5.55
CO_2	0.08	0.15	0.10	0.13
C_1	10.22	8.34	10.18	14.46
C_2	7.81	12.60	7.76	10.04
C_3	9.67	14.12	6.00	7.75
$I\text{-}C_4$	1.27	1.35	0.71	0.92
$N\text{-}C_4$	3.69	6.81	2.57	3.32
$I\text{-}C_5$	0.24	0.93	0.59	0.53
$N\text{-}C_5$	1.36	1.28	1.19	1.28
F-1	15.95	14.11	18.44	15.35
F-2	35.74	28.17	37.16	32.04
F-3	11.36	11.43	10.01	8.60

Table B-2   Thermodynamic properties of oil fractions used in EOS simulation

	Molecular weight	Tc (°F)	Pc (Psi)	Acentric factor	Z_c
Fraction-1	102.74	561.68	430.14	0.30337	0.398328
Fraction-2	194.11	800.28	277.19	0.41406	0.360714
Fraction-3	399.14	1152.01	160.77	0.80008	0.306332

Table B-3 Gas composition matching

		Differential 910-400 (psi)		Differential 400-100 (psi)		Flash 910-0 (psi)	
		data	calc	data	calc	data	calc
Energy	N_2	37.22	33.82	12.91	19.04	15.96	18.96
Field	CO_2	0.85	0.17	1.82	0.38	1.2	0.33
	C_1	46.08	51.73	46.09	45.76	35.57	36.42
	C_2	9.33	10.57	23.96	24.84	24.53	24.55
	C_3	3.81	2.91	10.96	7.95	13.27	13.99
	$I-C_4$	0.33	0.15	0.81	0.43	1.55	1.07
	$N-C_4$	1.06	0.42	2.22	1.13	5.32	3.13
	$I-C_5$	0.21	0.04	0.3	0.11	0.71	0.36
	$N-C_5$	0.38	0.07	0.44	0.17	1.02	0.57

		Differential 707-388 (psig)		Differential 388-180 (psig)		Flash 707-0 (psig)	
		data	calc	data	calc	data	calc
Zeigler	N_2	30.88	25.04	11.98	14.15	8.99	9.00
Field	CO_2	0.45	0.14	0.58	0.23	0.22	0.25
	C_1	49.6	58.91	52.61	56.44	27.36	34.86
	C_2	9.55	10.39	17.91	18.54	20.9	23.95
	C_3	6.06	4.48	12.22	8.69	25.88	23.05
	$I-C_4$	0.52	0.27	0.99	0.53	3.38	2.11
	$N-C_4$	1.33	0.58	2.41	1.11	9.85	5.02
	$I-C_5$	0.13	0.02	0.31	0.03	0.6	0.17
	$N-C_5$	0.34	0.08	0.43	0.14	2.03	0.79

		Differential 350 - 250 (psig)		Differential 250-150 (psig)		Differential 150-65 (psig)	
		data	calc	data	calc	data	calc
McCullum	N_2	7.95	9.07	3.37	2.78	0.51	0.42
Unit	CO_2	0.39	0.46	0.45	0.52	0.48	0.50
	C_1	47.39	46.44	40.23	39.39	19.15	22.66
	C_2	24.09	29.58	30.77	36.44	40.76	40.97
	C_3	15.57	11.65	20.73	16.74	29.58	27.68
	$I-C_4$	0.80	0.52	0.98	0.77	1.89	1.42
	$N-C_4$	2.28	1.89	2.60	2.80	5.76	5.31
	$I-C_4$	0.31	0.12	0.24	0.17	0.58	0.33
	$N-C_5$	0.45	0.13	0.34	0.18	0.75	0.35

APPENDIX C PVT ANALYSIS OF RESERVOIR FLUID, ALEX LEASE, ZEIGLER FIELD, FRANKLIN COUNTY

Procedures

The oil sample obtained from the well head was flashed to room condition, and the gas to oil ratio was measured to calculate the quantity of gas required for the recombination to the specified solution gas to oil ratio, as provided by Mike Gallagher of the Gallagher Drilling Company.

The casing gas sample and the oil samples were physically recombined to produce a fluid that has a solution gas to oil ratio of approximately 200 cubic feet of gas per barrel of oil. Subsequent flash separation analysis of this recombined fluid gave a gas to oil ratio of 195 cubic feet per barrel. The pressure to volume relationship and bubble-point pressure were determined by performing a constant composition expansion on a portion of the recombined fluid at a reservoir temperature of 95°F. The results of the constant composition expansion are presented in table C-3.

A single stage separator test was then carried out. The gas to oil ratio, formation volume factor, gas gravity, gas composition, and stock tank oil gravity were determined. The data are summarized in table C-4.

A three step, differential vaporization test was carried out on the recombined fluid at the reservoir temperature of 95°F. At each step, the equilibrium gas volume was measured first at cell conditions and then at standard conditions after removal of the gas from the cell. The gas was analyzed by gas chromatographic technique. Results of the gas analysis are reported in tables C-6 and C-7. At each step, a portion of the resulting oil sample was collected for determination of oil density and the solution gas to oil ratio. Results of the analysis are reported on table C-5.

The viscosity of the fluid was measured by a capillary viscometer at three pressure points, starting from the initial reservoir pressure of 1250 psig. The results are summarized in table C-8.

APPENDIX C *continued*

Table C-1 Field data

Company	Gallagher Drilling Company
Well	Alex No. 1
Field	Zeigler
Formation	Aux Vases
Location	Sec.19, T7S, R2E
County	Franklin
Original reservoir pressure	1250 psig
Total depth	2650 ft
Production interval	2,611-2,650 ft
Reservoir temperature	95°F
Date sampled	May 22, 1991
Separator temperature	85°F
Separator pressure	Atmospheric
Well status	Pumping
Gas-oil ratio (stock tank)	200 scf/stb
Water cut	Approximately 20%

Table C-2 PVT summary

Reservoir pressure (psig)	1250.0
Reservoir temperature (°F)	95.0
Density (g/cm3)	0.7869
Specific volume (scf/lb)	0.02036
Viscosity (Cp at 1250 psig)	1.96
Viscosity (Cp at 800 psig)	1.88
Formation volume factor (rb/stb)	1.138
Gas-oil ratio (scf/stb)	195.3
Compressibility coefficient (vol/vol/psix10^{-6})	
from 2000 psig to 4000 psig	5.46
from 1250 psig to 2000 psig	7.37
from 703 psig to 1250 psig	9.15
Thermal expansion (V° at 95°F/Vo at 77°F)	1.008

APPENDIX C   *continued*

Table C-3   Pressure to volume relationship

Pressure psig	Relative volume (V/Vsat)	Y-function
3980	0.9787	
3000	0.9832	
2000	0.9896	
1750	0.9910	
1500	0.9929	
1250	0.9950	
1000	0.9962	
914	0.9968	
821	0.9976	
756	0.9992	
737	0.9997	
Pb = 707	1.0000	
691	1.0026	7.77
671	1.0071	7.16
664	1.0088	7.00
655	1.0112	6.83
606	1.0256	6.38
512	1.0684	5.51
438	1.1270	4.80
393	1.1730	4.59
345	1.2462	4.24
314	1.3202	3.89
208	1.6562	3.64
165	2.1075	2.96

Bubble-point pressure = 707 psig
Vsat = Bubble-point fluid volume
Y-Function = (Psat-P)/(P((V/Vsat)-1))

Table C-4   Flash separator test

Saturation pressure (psig)	Reservoir temp. (°F)	Gas/oil ratio* (scf/stb)	Formation volume** factor	Stock tank oil gravity	Flash gas gravity
707	95	195.1	1.138	38.6	1.10

* Cubic feet of gas at 14.7 psig per barrel of oil at 60°F
** Barrel of saturated oil at 707 psig and 95°F per barrel of stock tank oil at 60°F

Table C-5 Differential vaporization at 95°F

Pressure (P) (psig)	Relative oil volume* (B_o) (rb/stb)	Oil density (γ_o) (gm/cc)	Solution gas/oil** (R_s) (scf/stb)	Gas expansion factor♦ (B_g) (scf/rcf)	Gas deviation factor (Z)
707	1.138	0.7870	195.1		
388	1.100	0.7878	184.4	29.71	0.88
180	1.065	0.7935	114.6	13.19	0.94
0	1.017	0.8151	0.0	0.93	0.99

* Volume at indicated pressure and temperature per volume of stock tank oil at 60°F

** Volume of gas at 14.7 psia and 60°F per volume of stock tank oil at 60°F

♦ Volume of gas at 14.7 psig and 60°F per volume of gas at indicated pressure and temperature

Table C-6 Gas composition

	Casing gas	Differential vaporization test 388 psig	Differential vaporization test 180 psig
CO_2	0.20	0.45	0.58
N_2	9.15	30.88	11.98
C_1	40.37	49.60	52.61
C_2	17.05	9.55	17.91
C_3	19.18	6.06	12.22
$I-C_4$	2.40	0.52	0.99
$N-C_4$	7.32	1.33	2.41
$I-C_5$	0.99	0.13	0.31
$N-C_5$	1.39	0.34	0.43
C_{6+}	1.94	1.13	0.56

APPENDIX C *continued*

Table C-7 Solution gas composition from flash separation

	707 psig	388 psig	180 psig
CO_2	0.22	0.51	0.48
N_2	6.99	3.70	0.60
C_1	27.36	26.88	19.24
C_2	20.90	25.51	27.93
C_3	25.88	28.68	34.31
$I-C_4$	3.38	3.13	3.75
$N-C_4$	9.85	8.12	9.47
$I-C_5$	0.60	1.00	1.15
$N-C_5$	2.13	1.29	1.45
C_{6+}	2.68	1.18	1.63

Table C-8 Oil viscosity at 95°F

Pressure (psig)	Oil viscosity (centipoise)
1250	1.96
707	1.88
180	2.19

APPENDIX D   PVT ANALYSIS OF RESERVOIR FLUID (SAMPLE 1), MCCULLUM UNIT, DALE CONSOLIDATED FIELD, FRANKLIN COUNTY

Procedures

PVT studies on this oil were carried out for the purpose of providing PVT data for the ISGS reservoir simulation study of Dale Consolidated Field. The McCullum lease has been producing since September 1984, and the producing gas to oil ratio of McCullum Nos. 2 and 3 wells, as measured on December 3, 1985, was 1,917 cubic feet per stock barrel of oil. Saturation pressure of the reservoir fluid was estimated using both the Standing (1952) and the Lasater (1958) correlations, and a solution gas to oil ratio of 1,917 scf/stb, oil API of 36°, gas gravity of 1.2, and reservoir temperature of 98°F. Both methods resulted in estimated bubble-point pressures of more than 3,000 psi.

This saturation pressure is obviously too high for a reservoir of only 3,109 feet deep. The reservoir has thus been producing below bubble-point pressure, and the produced gas has included both solution and free gases.

Because information on the initial reservoir pressure, the original solution gas to oil ratio, and the saturation pressure of the reservoir fluid was unavailable, two reservoir fluid samples with different saturation pressures were prepared and analyzed to provide information on the sensitivity of PVT properties to the variation of saturation pressure. The first sample was prepared with saturation pressure of 150 psig; the results of this study comprise appendix D. The second sample was prepared with saturation pressure of 350 psig; the results of the analysis are included in appendix E. Since it is uncertain whether any of the samples under study represent the original reservoir fluid, extreme care must be taken when using the results.

The oil sample obtained from the well head and the casing gas were physically recombined to give a reservoir fluid with a bubble-point pressure of 150 psig. Subsequent flash separation analysis of this recombined fluid gave a gas to oil ratio of 113 cubic feet of gas per barrel of stock tank oil. The pressure volume relationship and bubble-point pressure were determined by performing a constant composition expansion on a portion of the recombined fluid at a reservoir temperature of 98°F. The results of the constant composition expansion are presented in table D-3 of this report.

A single stage separator test was then carried out. The gas to oil ratio, formation volume factor, gas gravity, gas composition, and stock tank oil gravity were determined. These data are summarized in table D-4.

A three step, differential liberation test was carried out on the recombined fluid at the reservoir temperature of 98°F. At each step, the equilibrium gas volume was first measured at cell conditions and then at standard conditions after removal of the gas from the cell. The gas was analyzed by gas chromatographic techniques; the results are reported in table D-6. At each step, a portion of the resulting oil sample was collected for the determination of oil density and solution gas to oil ratio. The results of these analyses are reported in table D-5 .

The viscosity of the fluid was measured by capillary viscometer at three pressure points, starting from a pressure of 1400 psig and decreasing to 10 psig. The results are summarized in table D-7.

Table D-1 Field data

Company	Farrar Oil Company
Well	McCullum Community No. 2
Field	Dale Consolidated
Formation	Aux Vases
Location	Sec. 24, T7S, R4E
County	Franklin
Total depth	3209 ft
Production interval	3,158-3,176 ft
Reservoir temperature	98°F
Date sampled	July 11, 1991
Separator temperature	80°F
Separator pressure	Atmospheric
Well status	Pumping
Well tubing pumping pressure	50–100 psig
Production gas to oil ratio (Dec. 3, 1985)	1917 scf/stb
Water cut	Not significant

Table D-2 PVT summary

Reservoir pressure (psig)	1250
Reservoir temperature (°F)	98.0
Density (g/cm^3)	0.7902
Specific volume	0.02028
Viscosity (Cp at 1250 psig)	2.24
Viscosity (Cp at 800 psig)	2.09
Formation volume factor (barrel/barrel)	1.103
Gas to oil ratio (scf/stb)	113.2
Compressibility coefficient (vol/vol/psix10-6)	
from 2000 psig to 3000 psig	4.75
from 1500 psig to 2000 psig	5.50
from 1000 psig to 1500 psig	6.80
from 500 psig to 1000 psig	7.30
from 300 Psig to 500 psig	7.80
from 150 psig to 300 Psig	9.60

APPENDIX D   *continued*

Table D-3   Pressure to volume relationship

Pressure (psig)	Relative Volume (V/Vsat)
3000	0.9824
2500	0.9847
2000	0.9872
1500	0.9900
1000	0.9933
750	0.9952
500	0.9970
300	0.9986
150	1.0000
128	1.0115
122	1.0278
118	1.0432
109	1.0797
92	1.1486
84	1.2423
75	1.3282
59	1.4898
50	1.7013

Bubble-point pressure = 150 psig
V_{sat} = Bubble-point fluid volume

Table D-4   Flash separator test

Saturation pressure (psig)	Reservoir temp. (°F)	Gas/oil ratio* (scf/stb)	Formation volume factor**	Stock tank oil gravity♦	Flash gas gravity
150	98	113.2	1.103	37.0	1.31

* Cubic feet of gas at 14.7 psig per barrel of oil at 60°F
** Barrel of saturated oil at 150 psig and 98°F per barrel of stock tank oil at 60°F
♦ Molecular weight of the stock tank oil = 194.6

APPENDIX D *continued*

Table D-5 Differential vaporization at 98°F

Pressure (psig)	Relative oil volume* (B_o) (rb/stb)	Oil density (γ_o) (gm/cc)	Solution gas/oil** ratio (R_s) (scf/stb)	Gas expansion factor♦ (B_g) (rcf/scf)	Gas gravity
2000	1.061				
1000	1.085				
150	1.103	0.7902	113.2		
50	1.089	0.7942	92.4	4.30	1.06
10	1.062	0.7997	51.0	1.58	1.21

* Volume at indicated pressure and temperature per volume of stock tank oil at 60°F
** Volume of gas at 14.7 psia and 60°F per volume of stock tank oil at 60°F
♦ Volume of gas at 14.7 psig and 60°F per volume of gas at indicated pressure and temperature

Table D-6 Gas composition

	Field gas	Flash separation	Differential vaporization (150-50)	Differential vaporization (50-10)
CO_2	0.25	0.19	0.36	0.33
N_2	1.14	0.91	2.38	0.36
C_1	19.23	19.29	40.54	16.30
C_2	30.40	30.49	26.15	34.02
C_3	31.22	31.31	22.40	31.98
IC_4	2.84	2.84	1.46	2.75
NC_4	10.32	10.35	4.57	9.76
IC_5	1.32	1.33	0.63	1.24
NC_5	1.77	1.77	0.85	1.71
C_6+	1.51	1.52	0.68	1.56
Ave mw	37.61	37.63	30.22	37.94
Gas gravity	1.31	1.31	1.05	1.32

Table D-7 Oil viscosity

Pressure (psig)	Oil viscosity (centipoise)
1400	2.24
150	2.09
50	2.19
10	2.41

APPENDIX E   PVT ANALYSIS OF RESERVOIR FLUID (SAMPLE 2), MCCULLUM UNIT, DALE CONSOLIDATED FIELD, FRANKLIN COUNTY

Procedures

The oil sample obtained from the well head and the casing gas were physically recombined to give a reservoir fluid with a bubble-point pressure of 350 psig. Subsequent flash separation analysis of this recombined fluid gave a gas to oil ratio of 319.4 cubic feet of gas per barrel of stock tank oil. The pressure to volume relationship and bubble-point pressure were determined by performing a constant composition expansion on a portion of the recombined fluid at a reservoir temperature of 98°F. The results of the constant composition expansion are presented in table E-3.

A single stage separator test was then carried out. The gas to oil ratio, formation volume factor, gas gravity, gas composition, and stock tank oil gravity were determined. The data are summarized in tables E-4 and E-6.

A three step, differential liberation test was carried out on the recombined fluid at the reservoir temperature of 98°F. At each step, the equilibrium gas volume was measured first at cell conditions and then at standard conditions after removal of the gas from the cell. The gas was analyzed by gas chromatographic technique; the results are reported in table E-7. At each step, a portion of the resulting oil sample was collected for the determination of oil density and solution gas to oil ratio. The results of the analysis are reported in table E-5.

The viscosity of the fluid was measured by capillary viscometer at three pressure points, starting from a pressure of 1500 psig and decreasing to 10 psig. The results are summarized in table E-8.

APPENDIX E   *continued*

Table E-1   Field data

Company	Farrar Oil Company
Well	McCullum Community No. 2
Field	Dale Consolidated
Formation	Aux Vases
Location	Sec. 24, T7S, R4E
County	Franklin
Original reservoir pressure	1250 psig
Total depth	3,209 ft
Production interval	3,158-3,176 ft
Reservoir temperature	98°F
Date sampled	July 11, 1991
Separator temperature	80°F
Separator pressure	Atmospheric
Well status	Pumping
Gas to oil ratio (stock tank)(Dec. 3, 1985)	1917 scf/stb
Water cut	No

Table E-2   PVT summary

Reservoir pressure (psig)	1250
Reservoir temperature (°F)	98.0
Density (g/cm^3)	0.7902
Specific volume (scf/lb)	0.02028
Viscosity (Cp at 1400 psig)	1.35
Viscosity (Cp at 350 psig)	1.24
Formation volume factor (barrel/barrel)	1.213
Gas to oil ratio (scf/stb)	319.4
Compressibility coefficient (vol/vol/psix10^{-6})	
from 2000 psig to 3000 psig	5.84
from 1500 psig to 2000 psig	7.35
from 1000 psig to 1500 psig	8.60
from 500 psig to 1000 psig	9.60

APPENDIX E *continued*

Table E-3 Pressure to volume relationship

Pressure (psig)	Relative volume (V/V_{sat})
3000	0.9803
2500	0.9829
2000	0.9868
1500	0.9906
1300	0.9923
1100	0.9936
900	0.9953
700	0.9970
500	0.9987
360	0.9999
350	1.0000
335	1.0500
315	1.1180
292	1.2100
250	1.3800
180	1.5825

Bubble-point pressure = 350 psig
Vsat = Bubble point fluid volume

Table E-4 Flash separator test

Saturation pressure (psig)	Reservoir temp. (°F)	Gas/oil ratio* (scf/stb)	Formation volume factor**	Stock tank oil gravity	Flash gas gravity
350	98	319.4	1.213	37.0	1.30

* Cubic feet of gas at 14.7 psig per barrel of oil at 60°F
** Barrel of saturated oil at 350 psig and 98°F per barrel of stock tank oil at 60°F

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APPENDIX E *continued*

Table E-5 Differential vaporization at 98°F

Pressure (psig)	Relative oil volume* (Bo)	Oil density (γ_o)	Solution gas/oil factor** (Rs)	Gas expansion◆ (Bg)	(γ_g)
2000	1.197				
1000	1.205				
350	1.213	0.763	319.4		
250	1.190	0.773	292.0	17.9	0.94
150	1.130	0.784	245.1	10.7	1.00
65	1.069	0.795	164.5	4.5	1.20
15	1.030	0.805	82.9	2.1	1.40
0	1.017	0.822	0.0		1.57

* Volume at indicated pressure and temperature per volume of stock tank oil at 60°F

** Volume of gas at 14.7 psia and 60°F per volume of stock tank oil at 60°F

◆ Volume of gas at 14.7 psig and 60°F per volume of gas at indicated pressure and temperature

Table E-6 Gas composition

	Casing gas	Flash separation test (350 psig)	(15 psig)
CO_2	0.25	0.29	0.06
N_2	1.14	0.71	0.08
C_1	19.23	17.75	0.59
C_2	30.40	30.70	23.07
C_3	31.22	33.88	51.09
IC_4	2.84	2.81	4.63
NC_4	10.32	9.41	15.21
IC_5	1.32	1.04	1.64
NC_5	1.77	1.37	2.09
C_{6+}	1.51	1.05	1.53
Ave mw	37.61	37.39	45.17
Gas gravity	1.31	1.30	1.57

APPENDIX E *continued*

Table E-7 Gas composition from differential vaporization tests

	(350-250) psig	(250-150) psig	(150-65) psig	(65-10) psig
CO_2	0.39	0.45	0.48	0.23
N_2	7.98	3.37	0.51	0.02
C_1	47.39	40.23	19.15	4.99
C_2	24.09	30.77	40.76	36.58
C_3	15.57	20.73	29.58	41.87
IC_4	0.80	0.98	1.89	3.12
NC_4	2.28	2.60	5.76	9.93
IC_5	0.31	0.26	0.58	1.03
NC_5	0.45	0.34	0.75	1.36
C_{6+}	0.73	0.27	0.55	0.88
Ave mw	27.10	28.73	34.60	40.44
Gas gravity	0.94	1.00	1.20	1.40

Table E-8 Oil viscosity

Pressure (psig)	Oil viscosity (centipoise)
1500	1.50
350	1.39
150	2.33
65	2.44
10	2.69

APPENDIX F PVT ANALYSIS OF RESERVOIR FLUID, ENERGY FIELD, WILLIAMSON COUNTY

Procedures

Casing gas and well head oil were collected from the Morgan Coal No. 6 well of Energy Field in Williamson County, Illinois, for the purpose of performing reservoir fluid analyses. Because of uncertainty regarding the actual solution gas to oil ratio and original reservoir fluid saturation pressure, it was decided to recombine the well head oil with different amounts of solution gas to produce three reservoir fluids of varying gas to oil ratios. The basic PVT properties of these samples, such as saturation pressure, gas to oil ratio, and oil formation volume factors, were determined and later summarized (table F-2).

The pressure to volume relationship and bubble-point pressure were determined by performing a constant composition expansion on each of these recombined fluids at a reservoir temperature of 84°F. The results of the constant composition expansion are presented in tables F-3 to F-5.

A single stage separator test on the sample with saturation pressure of 910 psig was then carried out. The gas to oil ratio, formation volume factor, gas gravity, gas composition, and stock tank oil gravity were determined. The data are summarized in table F-6.

A three step, differential vaporization test was carried out on the same recombined fluid at the reservoir temperature of 84°F. At each step, the equilibrium gas volume was first measured at cell conditions and then at standard conditions after removal of the gas from the cell. The gas was analyzed by gas chromatographic technique; the results are reported in table F-8. At each step, a portion of the resulting oil sample was collected for the determination of oil density and solution gas to oil ratio. The results of the analysis are reported in table F-7.

The viscosity of the fluid was measured by capillary viscometer at four pressure points, starting from the initial pressure of 2,000 psig. The results are summarized in table F-9.

Discussion

The basic PVT properties of three recombined reservoir fluid samples obtained by recombination of the casing gas and well-head oil produced from the Morgan Coal No. 6 well were measured. From the results presented in table F-2 and figures F-1 and F-2, the relationships between saturation pressure, solution gas to oil ratio, and oil formation volume factor are close to linear within the limits of investigation. These relationships can be used by reservoir or production engineers for the calculation of oil reserves as well as for planning production strategy.

The differential vaporization test of sample 3 was performed giving the oil formation volume factors, gas to oil ratios, oil density, gas expansion factors, and oil viscosity at the pressures of 400 psig and 100 psig. As shown on table F-7, the change in PVT properties is much smaller near the initial bubble-point pressure of 910 psig than at a lower saturation pressure of 100 psig. This observation is a reflection of the facts that (a) the solubilities of gases in the oil phase are in the order of $N_2 < C_1 < CO_2 < C_2 < C_3 < C_4$; and (b) the effect of dissolved gases on the oil swelling and oil viscosity reduction are also in the same order of $N_2 < C_1 < CO_2 < C_2 < C_3 < C_4$; and (c) the solution gases of the Energy Field contain
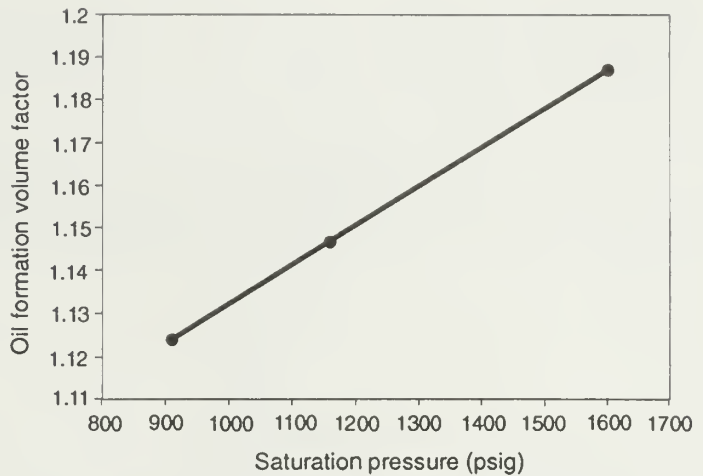
Figure F-1 Saturation pressure relative to B_o (Energy Field, Morgan Coal No. 6).
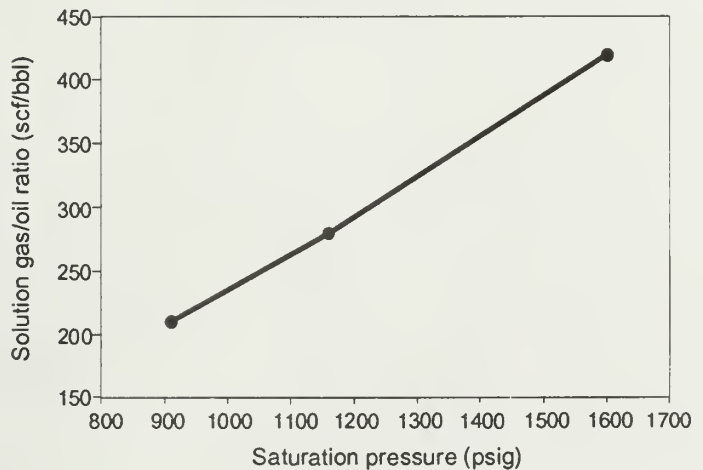

Figure F-2 Saturation pressure relative to GOR (Energy Field, Morgan Coal No. 6).

relatively large amounts of nitrogen (15.96%), propane (13.27%) and butane (5.32%).

During differential vaporization, as the pressure of the sample is decreased, the less soluble nitrogen and methane are being released from the reservoir fluid. As shown in table F-8, the composition of the gases liberated from 910 to 400 psig contain 37.32% of nitrogen and 46.08% of methane. The volume of gases released is only 21% of the total solution gas. The change in physical properties such as oil swelling and viscosity reduction are minimal because (1) the effects of dissolved nitrogen and methane on the oil swelling and viscosity reduction are smaller, and they are also partly counter-balanced by the increase in pressure required to dissolve to gases; and (2) the amount of gas dissolved per unit pressure is smaller.

At low saturation pressure, the change in oil properties measured reflects the effect of dissolved propane and butane on the oil. Their solubilities are large, and the effect on the volume and viscosity is much more pronounced for a small change in pressure.

This observation may partially explain the rapid decline in reservoir pressure during primary production. For a solution gas drive reservoir, the amount of gases released during the initial phase of pressure depletion is small, and thus does not provide a strong driving force for the production of oil.

Conversely, most of the dissolved gases, such as propane and butane, are kept in solution up to relatively low pressure. Thus a lower oil viscosity and higher oil saturation will be maintained and help to improve oil recovery during the water-flood phase of the project.

APPENDIX F *continued*

Table F-1 Field data

Company	Budmark Oil Company
Well	Morgan Coal No. 6
Field	Energy
Formation	Aux Vases
Location	Sec.4, T9S, R2E
County	Williamson
Original reservoir pressure	921 psig
Total depth	2,400 ft
Production interval	2,400 ft
Reservoir temperature	84°F
Date sampled	July 11, 1991
Separator temperature	80°F
Separator pressure	Atmospheric
Well status	Pumping
Gas to oil ratio (stock tank)	Not measured
Water cut	Approximately 50%

Table F-2 PVT summary

Sample 1	
Saturation pressure (psig)	1600.0
Reservoir temperature (°F)	84.0
Formation volume factor (barrel/barrel)	1.187
Gas to oil ratio (scf/stb)	419.4
Compressibility coefficient (vol/vol/pix10^{-6})	
from 2000 psig to 2500 psig	7.7
from 1600 psig to 2000 psig	8.4
Sample 2	
Saturation pressure (psig)	1160.0
Reservoir temperature (°F)	84.0
Formation volume factor (barrel/barrel)	1.147
Gas to oil ratio (scf/stb)	279.5
Compressibility coefficient (Vol/Vol/psix10^{-6})	
from 2000 psig to 2500 psig	7.4
from 1500 psig to 2000 psig	8.2
Sample 3	
Saturation pressure (psig)	910.0
Reservoir temperature (°F)	84.0
Formation volume factor (barrel/barrel)	1.124
Gas to oil ratio (scf/stb)	210.0
Compressibility coefficient (vol/vol/psix10^{-6})	
from 2000 psig to 2500 psig	6.2
from 1600 psig to 2000 psig	6.7
from 1000 psig to 1500 psig	8.2

APPENDIX F   *continued*

Table F-3 Pressure to volume relationship of sample 1 at reservoir temperature of 84°F

Pressure (psig)	Relative Volume (V/Vb)
2500	0.994
2000	0.998
1800	0.999
Pb = 1600	1.000
1550	1.006
1434	1.029
1326	1.050
1230	1.069
903	1.178
594	1.437
370	2.008
213	3.178

$$Relative\ volume = \frac{Total\ volume}{Oil\ volume\ at\ bubble\text{–}point\ pressure}$$

Table F-4 Pressure to volume relationship of sample 2 at reservoir temperature of 84°F

Pressure (psig)	Bo (V/Vsat)
2494	0.988
2012	0.991
1523	0.996
1310	0.998
Pb = 1160	1.000
1108	1.006
1065	1.013
996	1.025
926	1.043
849	1.062
663	1.149
550	1.241
439	1.391
341	1.622
286	1.821
234	2.116

$$Relative\ volume = \frac{Total\ volume}{Oil\ volume\ at\ bubble\text{–}point\ pressure}$$

APPENDIX F *continued*

Table F-5 Pressure to volume relationship of sample 3 at reservoir temperature of 84°F

	Pressure (psig)	Relative volume (V/Vb)
	2500	0.988
	2000	0.992
	1500	0.995
	1221	0.997
	1010	0.999
Pb =	910	1.000
	869	1.005
	846	1.010
	816	1.017
	791	1.024
	747	1.036
	667	1.064
	541	1.134
	460	1.209
	375	1.328
	305	1.478
	263	1.630

$$Relative\ volume = \frac{Total\ volume}{Oil\ volume\ at\ bubble\text{–}point\ pressure}$$

Table F-6 Flash separator test

Saturation pressure (psig)	Reservoir temp. (°F)	Gas/oil ratio* (scf/stb)	Formation volume factor**	Stock tank oil gravity	Flash gas gravity
910	84	210.0	1.124	38.8	1.03

 * Cubic feet of gas at 14.7 psig per barrel of oil at 60°F
** Barrel of saturated oil at 910 psig and 84°F per barrel of stock tank oil at 60°F

APPENDIX F *continued*

Table F-7. Differential vaporization of reservoir fluid (sample 3) at 84°F

Pressure (psig) (p)	Oil volume factor* (rb/stb) (Bo)	Solution gas/oil ratio** (scf/stb) (Rs)	Gas expansion factor♦ (cuft/cuft) (Bg)	Oil density (gm/cm³)	Gas specific gravity (air = 1)
2500	1.111				
1500	1.118				
910	1.124	210.1		0.783	
400	1.072	166.2	31.1		0.85
100	1.039	65.1	8.4	0.795	0.92
0	1.011	0			

* Volume at indicated pressure and temperature per volume of stock tank oil at 60°F
** Volume of gas at 14.7 psia and 60°F per volume of stock tank oil at 60°F
♦ Volume of gas at 14.7 psig and 60°F per volume of gas at indicated pressure and temperature

Table F-8 Gas composition

	Casing gas	Flash separator test 910 psig	Differential vaporation test 400 psig	100 psig
CO_2	0.30	1.20	0.85	1.82
N_2	12.49	15.96	37.32	12.91
C_1	32.58	35.57	46.08	46.09
C_2	22.60	24.53	9.33	23.96
C_3	17.44	13.27	3.81	10.98
IC_4	2.05	1.55	0.33	0.81
NC_4	7.45	5.32	1.06	2.22
IC_5	1.16	0.71	0.21	0.30
NC_5	1.74	1.02	0.38	0.44
C_{6+}	1.88	0.87	0.63	0.43
Ave mw	32.58	30.24	24.4	26.53
Gas gravity	1.13	1.05	0.8	0.92

Table F-9 Viscosity of reservoir fluid (sample 3) at 84°F

Pressure (psig)	Viscosity (Cp)
2000	1.64
910	1.55
400	1.80
100	2.31

APPENDIX G   SAMPLE CALCULATION USING EQUATION 1

Example calculation of bubble-point pressure using equation 1

Where

$$\text{API gravity of oil} = 38.8$$

$$\text{Molecular weight of oil} = 199.3$$

$$\text{Solution gas to oil ratio} = 419.4 \text{ scf/stb}$$

$$\text{Reservoir temperature} = 84^\circ F$$

$$\text{Density of oil } (\gamma_o) = \frac{141.5}{131.5 + 38.8}$$

$$= 0.831 \text{ gm/cc}$$

$$\text{Mole fraction of gas } (Y_g) = \frac{\dfrac{Rs}{379.3}}{\dfrac{Rs}{379.3} + 350 \times \dfrac{\gamma_o}{MW}}$$

$$= \frac{\dfrac{419.4}{379.3}}{\dfrac{419.4}{379.3} + 350 \times \dfrac{0.831}{199.3}}$$

$$= 0.4311$$

Calculation of pseudo critical temperature of gas mixture

	T_c	X_{ci}
N_2	−232.4	17.49
CO_2	87.9	0.33
C_1	−116.6	37.46
C_2	90.1	24.46
C_3	206	14.00
IC_4	275	1.47
NC_4	305.7	3.49
IC_5	369.1	0.43
NC_5	380.7	0.84

Where

$$T_{cm} \text{ of gas mixture} = \Sigma x_i\, T_{ci} = -13.66$$

$$P_b = \frac{65.23\,(460{+}84)\,(0.679\ Exp\,(2.786\,Y_g) - 0.323)}{(60 - 13.66)}$$

$$= 1480 \text{ psi}$$

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