

PVT – COMPARISON OF ESTIMATED TO MEASURED FLUID PROPERTIES

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Abstract

A successful approach to oil and gas reservoir development requires knowledge of reservoir fluid properties. It is therefore essential to determine the fluid's Pressure-Volume-Temperature (PVT) behavior in order to obtain the necessary parameters for proper reservoir management as well as satisfy regulatory classification requirements. Experience has demonstrated that PVT data obtained in a laboratory is the preferred approach to fluid property description. When laboratory data are not available, correlations or equation of state computations are often used to estimate reservoir fluid behavior. Correlations are approximations to specific regional properties, and untuned equation of state calculations can produce erroneous results. Using case histories, we compare the inherent limitations in the calculated approach to PVT data derived from laboratory studies, and re-acquaint reservoir engineers with field sampling procedures, laboratory testing, and data analyses.

Introduction

A considerable amount of planning is required for proper engineering, development, and production of an oil or gas reservoir. Any plans for field development should include a program of data acquisition that facilitates future reservoir engineering needs. This data acquisition program should include a variety of well logs, core evaluation, and characterization of the reservoir fluids. Core analysis in combination with electric and nuclear logs evaluates reservoir rock physical properties, fluids encountered in the rock pore space, and multiphase fluid flow within the core samples. Production logs provide information relating to reservoir production rates. If calculations made by reservoir engineers are to reflect optimized reservoir production, then the properties of the reservoir fluids must also be known to reasonable accuracy. This paper focuses on the evaluation of the hydrocarbon fluids contained in a reservoir.

Development strategies are critically dependent on reservoir fluid phase behavior. This is true whether considering ordinary gas drives or enhanced oil recovery using carbon dioxide. Reservoir fluid properties can be obtained from laboratory measurements, generalized correlations, or derived from equation of state (EOS) based calculations. Of these methods, generalized correlations and EOS calculations are often favored because they are easier to use and less expensive than laboratory measurements.

Generalized correlations usually require a minimal amount of data to predict a specific parameter that describes the reservoir fluid. For example, Standing's¹ correlations require knowledge of the gas-oil-ratio (GOR), stock tank oil gravity in °API, gas gravity, and reservoir temperature to provide an estimate for the bubble point pressure of a hydrocarbon. The estimated fluid properties, however, can be highly inaccurate. These empirical relationships, whether graphical or mathematical, are often based on relatively

small databases which represent data from specific geographical regions. Thus extrapolation of correlations to other geographical regions and reservoir fluids can become a tenuous proposition.

Desktop computers provide engineers easy access to powerful EOS based predictive tools for reservoir fluids. These simulators are capable of calculating saturation pressures, critical points, phase envelopes, and viscosity. This software is capable of simulating separator tests, constant mass expansions, and depletions with only a modest amount of laboratory and field data input to initiate any calculation. These data consist of gas and liquid composition analyses and reservoir temperature. If a fluid recombination is required, then the GOR and primary separator conditions are entered prior to initiating the simulation. The calculated fluid properties, however, may be correct or erroneous depending on the fluid's similarity to the simulator's default fluid. It is often true that without collaborative laboratory data to adjust EOS parameters, a simulation provides the wrong answer with precision to several decimal places.

Because of the uncertainties associated with using correlations and EOS calculations, experimental studies are necessary to accurately describe hydrocarbon phase behavior. This is particularly true in newly found reservoirs where representative samples of the original reservoir can be obtained only when the reservoir pressure is equal to or greater than the original saturation pressure.

The objective of this paper is two-fold. The first is to re-acquaint practicing engineers with reservoir fluid types, field sampling, laboratory measurements, and data analysis. Secondly, to compare a few laboratory results with those obtained from calculations using correlations and equations of state. For oil systems, the results of two laboratory studies will be compared with predictions from Standing¹, Lasater², Al-Marhoun³, and Vasquez and Beggs⁴ correlations along with Peng-Robinson⁵ EOS calculations. Four experimental gas condensate studies will be compared with the Nemeth-Kennedy⁶ correlation and Peng-Robinson EOS predictions.

Types of Reservoir Fluid

There are five types of reservoir fluids^{7,8}. They are normally called black oil, volatile oil, retrograde gas, wet gas, and dry gas. Five types of fluids have been defined because each fluid requires a different engineering approach. This places a requirement on early identification of reservoir fluid type. Fluid type is a central issue in many decisions regarding the reservoir. The type and size of surface equipment, method of sampling, determination of oil-in-place, oil and gas reserve calculations, depletion strategies, and enhanced oil recovery are all very dependent on the type of fluid.

Black oils are identified by GOR's up to 2,000 scf/STB, stock tank oil gravities below 45° API, and formation volume factors (FVF) below 2 res bbl/STB. Generally, the stock tank oil is dark, indicating the presence of heavy hydrocarbons. The producing GOR increases with production when the reservoir pressure falls below the bubble point pressure.

Volatile oils have GOR's in the range of 2,000 to 3,300 scf/STB, oil gravities of 40° API or higher, and a formation volume factor greater than 2 res bbl/STB. These oils are often referred to as near-critical oils because they exhibit the properties of oil existing in the reservoir at a temperature near its critical temperature. The producing GOR increases with production and at pressures below the bubble point pressure. Stock tank oils are usually brown but can be orange and sometimes green. Compositions determined in the laboratory will show 12.5 to 20 mole percent heptane plus.

A retrograde gas reservoir is characterized by GOR's in the range of approximately 3,300 to 150,000 scf/STB and liquid gravities between 40° and 60° API. Liquid gravities increase as reservoir pressure falls below the dew point. The liquid can be lightly colored, brown, orange, green, or water white. Producing GOR increases after the reservoir pressure falls below the dew point. Generally, the heptane plus fraction for a retrograde gas will be below 12.5 mole percent.

Wet gases produce stock tank liquids with the same range of gravities as retrograde gases. The gravity of the liquid does not change during production, and the liquid is usually water white. Producing GOR will remain constant during production.

Dry gas reservoirs produce primarily methane along with some intermediate components. Generally the gas does not contain sufficient heavier molecules to form a liquid at the surface. As the surface operating conditions usually fall outside of the phase envelope, no liquids are formed at the surface or in the reservoir.

Fluid Sampling

Reservoir fluids should be sampled very early in the life of a reservoir. These samples should be taken before the reservoir experiences any significant declines in pressure. Regardless of the reservoir fluid type, there are two methods of sampling: surface sampling^{9,12} and bottom-hole sampling^{10,11}. Surface samples are obtained for gas, retrograde gas, and oil reservoirs producing above the bubble point or dew point pressure. Bottom-hole samples should be considered from wells whose bottom-hole flowing pressure is lower than the bubble point pressure or wells producing from both a gascap and oil zones.

All wells should be conditioned prior to sampling. For surface sampling, the well should be stabilized at the lowest flow rates possible for continuous stable flow. Samples can be taken after establishing a stable flow rate and GOR for several hours. If possible, surface samples should be obtained at a minimum GOR. Stabilized surface rates resulting in bottom-hole pressures below the saturation pressure will likely produce samples that are not representative of the reservoir fluid. In bottom-hole sampling, well conditioning generally consists of a period of reduced flow followed by shut-in. Samples can be obtained once the well has reached its maximum static pressure.

For surface sampling, gas and liquid samples must be obtained from the high-pressure separator. Generally the gas samples are collected in evacuated cylinders attached to the top of the separator or gas meter run. Connecting a water filled sample bottle to the oil leg of the separator and displacing the water with the oil can collect a liquid sample. Safety considerations require draining additional water from the sample cylinder to provide a gas cap and insure that the sample cylinder will not be exposed to unsafe pressures resulting from temperature increases.

Bottom-hole samples can be obtained using two different procedures. The first procedure lowers the open sampler to a specified depth and then closes the sampler prior to retrieval. The second procedure lowers the well sampler to a specific depth, and the well is slowly flowed for a short period of time so that fresh sample is introduced into the wellbore. At this point the sampler is closed and retrieved to the surface. Generally bottom-hole samples should be transferred to a separate cylinder and the saturation pressure determined. A duplication of samples with reproducible saturation pressures is generally a requirement.

For both surface and bottom-hole sampling it is necessary to insure that a sufficient quantity of sample is available to complete all laboratory evaluations.

Laboratory Measurements and Analyses

A reservoir fluid study on non-critical oils should consist of five tests: composition of the reservoir fluid, pressure/volume relations, differential liberation, viscosity, and separator tests.

Reservoir fluid composition is the most complete description of the fluid that can be made. Oil and gas samples are analyzed using gas chromatography techniques. These data form the basis for any reservoir fluid study and enable the determination of the well stream composition and physical recombination. These data are necessary to estimate fluid properties from correlations and EOS calculation. Generally the compositional reports^{8,13} consist of hydrocarbon components to C_{11+} for gas samples and components to approximately C_{30+} for liquid samples.

Pressure/Volume (PV) relations^{1,8,13} are obtained from a constant composition expansion of the reservoir fluid. After a gas and liquid are charged into a cell at reservoir temperature and in a ratio equal to the separator GOR, pressure is applied until reaching reservoir pressure. The single-phase fluid within the cell should be representative of the reservoir fluid. Then pressure is reduced in steps and the change in volume is measured. Above the bubble point, the compressibility of the single-phase fluid is measured. Below the bubble point, the volume of each phase is measured as a function of pressure.

Differential liberation measurements^{1,8,13} are performed after the PV relations are established and verified graphically. The fluids within the cell are brought to single phase at the bubble point pressure. Then the pressure is reduced in steps, the fluid mixture is allowed to equilibrate, and at each step the gas is removed from contact with the oil in the cell. These steps determine the amount of gas in solution as a function of pressure and the shrinkage of the oil as the gas is released from solution. Additionally during this process the properties of the evolved gas are measured, including specific gravity and gas z-factor. Oil density can be determined as a function of temperature. These data provide most of the information reservoir engineers need for calculations. The total formation volume factor (FVF), B_t , is determined from the PV relation. The oil FVF, B_o , and solution GOR, R_s , are derived from the differential liberation measurements. The gas FVF, B_g , is derivable from the amount of liberated gas.

Viscosity^{1,8} is a measure of the resistance to flow exerted by a fluid. This quantity should be measured as a function of pressure at reservoir temperature.

Separator tests^{1,8,13} should be performed to evaluate the behavior of the reservoir fluid during its passage up the tubing, through the separators, and into the stock tank. Generally four tests are performed at various pressures to determine the optimum separator operating conditions. That is, to define the conditions of the separator for which the lowest GOR and highest stock tank oil gravity are present. These tests measure the oil FVF, B_o , and solution GOR, R_s .

Retrograde gas reservoir fluid study should include fluid composition analysis, a constant composition expansion^{1,8,13}, a constant volume depletion^{1,8,13}, and a separator test^{1,8,13}. As previously mentioned, a compositional analysis of the separator gas and separator liquid forms the basis of any fluid study.

A constant composition expansion allows the measurement of the retrograde dew point, the fluid compressibility above the dew point, and the gas and liquid volumes below the dew point. The retrograde liquid volume can be determined as a percentage of the pore space (cell volume). A gas FVF, B_g , is derivable from this data.

A constant volume depletion (CVD) is performed after the PV relations are established and the fluids in the cell are brought to single phase at the dew point pressure. This depletion generally consists of a series of expansions and constant pressure displacements of the reservoir fluid such that the sample volume in the cell remains constant. The reservoir gas produced during each constant-pressure displacement is sampled and the volume determined. Gas chromatography is used to determine the composition of each gas sample. The z-factor of the produced gas, the two-phase z-factor¹⁴ of the hydrocarbons remaining in the cell, and the volume of the liquid remaining in the cell are determined at each depletion step. Data obtained during a CVD^{1,8,13} are used to calculate the cumulative recovery. The objectives are to convert depletion gas compositions to volumes of separator gas and stock tank oil, and to initiate an economic evaluation of the reservoir. Liquid volume remaining in the cell is of importance as it reflects a true liquid volume left in the pore spaces.

Separator tests are performed to optimize separator conditions and to determine shrinkage of the separator liquid to stock tank liquid ratio. Additionally liquid gravity is measured and compared with field generated data.

Volatile oil^{7,8} or near-critical fluid studies consist of fluid composition analysis, a constant composition expansion, a constant volume depletion, and separator tests. Volatile oils undergo a very high shrinkage as the pressure drops below the bubble point. This creates a high gas saturation in the pore spaces. Since the gas/oil relative permeability characteristics favor gas permeability, the free gas achieves high mobility. Fortunately this gas is a rich gas condensate. Typical material balance techniques used in an oil study can not account for a produced gas that is a retrograde condensate. This necessitates a compositional material balance approach and requires a constant volume depletion test.

Oil System Comparisons

Two oil wells, BOC-OW1 and GOC-OW4, will be used in this comparison of laboratory measurements with predictions derived from correlations and equation of state calculations. Along with general well data, Table 1 lists the necessary parameters useful in estimating fluid properties for these wells. Using the previously given reservoir fluid typing guidelines, both wells fall into the black oil category. That is, both wells have a GOR below 2000 scf/STB and liquid gravity below 45 °API. These wells, however, were sampled differently. Well BOC-OW1 was sampled at the high-pressure separator while bottom-hole sampling was used to retrieve a sample from GOC-OW4. The compositional analyses through C₇₊ for these wells are shown in Table 2 and Table 3, respectively. The heptane plus fractions for both wells is greater than 20 mole percent and consistent with the notion that both should be considered oil wells, and both should exhibit bubble points.

Comparisons will be restricted to a few important quantities: bubble point pressure, oil FVF, GOR, and viscosity. As previously mentioned, the correlations used in these comparisons are those of Standing, Lasater, Vasquez and Beggs, and Al-Marhoun. Equations of state calculations use the Peng-Robinson equation of state. Preliminary calculations using the EOS approach assume that only field data and compositional analyses are available for these wells. This implies that the tuning parameters within the EOS calculations are set at their default values. All viscosity estimates are based on the method suggested by Pedersen^{15,16} and coworkers.

The estimated bubble point pressures are compared to experimentally derived values in Table 4. For well BOC-OW1, the correlations generally underestimate the bubble point pressure, while the EOS

calculates a bubble point pressure above that observed in the laboratory. Results from Standing and Vasquez and Beggs show the largest discrepancies at -29.1% and -21.8%, respectively. Al-Marhoun's correlation, and EOS calculations are within acceptable error margins.

Results for well GOC-OW4 illustrate the opposite behavior from BOC-OW1 in that the correlations generally overestimate the bubble point pressure while the EOS predicts lower values. The largest discrepancy is calculated by the Lasater correlation, 18.4%, while the Standing correlation computes a result with the lowest percentage error of 3.5%.

Laboratory analyses for both wells included differential liberation measurements and viscosity measurements. These data, in conjunction with the PV relations for these wells, were used to adjust the EOS. In principle, an adjusted or tuned equation of state should describe the physical properties of a fluid with good accuracy. The tuned EOS was then used to re-calculate the behavior of the oil FVF, GOR, and viscosity. In addition, the oil FVF's were calculated using the Standing and Vasquez and Beggs correlations. These estimated values reflect the oil FVF at the bubble point.

For well BOC-OW1, the results for the oil FVF are illustrated in Figure 1, GOR comparisons are shown in Figure 2, and the viscosity comparison is illustrated in Figure 3. Initial oil FVF calculations overestimate the experimental results by 2.6%. After tuning the EOS, the results obtained for the oil FVF underestimate the experimental values by approximately 4%. Standing underestimates the oil FVF by 1.5% while Vasquez and Beggs underestimate the oil FVF by approximately 6%.

The calculations for the GOR behavior below the bubble point pressure illustrate similar tendencies; however, the errors are more significant. The calculated values for the GOR prior to tuning the EOS show an average deviation of 75%. After tuning the EOS the average deviation is reduced to approximately 11%. Viscosity calculations for this well illustrate very significant deviations from laboratory measurements. Above the bubble point pressure the calculated viscosity diverges from the experimental data and shows a 44% deviation at reservoir pressure. A similar divergence is observed below the bubble point. In this region a maximum deviation of 45% is seen at conditions representing the stock tank. Using a tuned EOS to calculate viscosity fails to improve the disagreement between the calculated values and laboratory observations. For this well, it can be concluded that the approach used by Pedersen and coworkers does not adequately describe the viscosity behavior.

For well GOC-OW4, the results for the oil FVF are illustrated in Figure 4, GOR comparisons are shown in Figure 5, and the viscosity comparison is illustrated in Figure 6. Calculations of oil FVF prior to EOS tuning show an average deviation of approximately 2% from laboratory measurements. After adjusting the EOS, the oil FVF underestimates laboratory results with an average deviation of 4.8%. For this well, Standing predicts an oil FVF that is 12.4% below the experimental value. Vasquez and Beggs predict a value 31.8% lower than laboratory measurements. On the average, the estimated values for GOR deviate from the experimental results by 24%. However, a tuned EOS predicts GOR values that deviate from laboratory results by only 1.4%. The viscosity calculations deviate from experimental values by approximately 7.4% over the entire range of measurements. Viscosity estimates are not improved significantly when using the tuned EOS.

For these wells, the results from correlations and EOS calculations vary widely in agreement when compared to experimental data. As shown in Table 4 and Figure 2, computed values may show excellent agreement with laboratory measurements or demonstrate deviations in the range of 75%. This large range of uncertainties prevents usage of estimated values in predictive engineering calculations and strongly

indicates the necessity of laboratory measurements. However, the estimated values are useful in determining the appropriate method of sampling in preparation for laboratory analyses.

Gas Condensate Comparison

Predictions derived from correlations and equation of state calculations will be compared against laboratory data from four wells: GCC-PR1, GOC-CC7, COG-Z1, and POC-M4. These well data are presented in Table 5. Compositional analyses performed on high pressure separator samples from these wells are shown in Table 6 through Table 9, respectively. Again using the reservoir fluid typing criteria, these wells fall into the category of gas condensate by virtue of having GOR's greater than 3300 scf/STB, liquid gravities in the range from 40° to 60° API, and heptane plus fractions less than 12.5 mole percent.

The comparisons will be restricted to a few quantities: dew point pressures, gas z-factors, and retrograde liquid volumes determined during constant volume depletions. The Nemeth-Kennedy correlation is used to predict the dew point pressure. Equation of state calculations use the Peng-Robinson equation of state. Sage and Olds¹⁷ developed a correlation to estimate dew point pressures and gas FVF; however, this correlation is limited to low reservoir pressures and condensate gravity above 52° API. Organick and Golding¹⁸ proposed a separate method to estimate the saturation pressure of a gas condensate. Their method requires calculating an average molal boiling point based on results obtained from distillation measurements, and determination of a weight averaged equivalent molecular weight. Since distillation data are not available, this correlation will not be used to estimate dew points.

The estimated dew point pressures are compared to laboratory measurements in Table 10. Nemeth-Kennedy predictions for well GCC-PR1 are in excellent agreement with laboratory data. However, correlation predictions for the other wells deviate up to 20% from the observed values. The dew point predictions using the default EOS show large deviations for all wells with a maximum calculated deviation of 27.2% for well COG-Z1.

Experimental constant volume depletion results for GCC-PR1 and GOC-CC7, in conjunction with PV data and retrograde liquid curves, were used to tune each EOS. The adjusted EOS was then used to calculate the behavior of gas z-factors and retrograde liquid volumes during a simulated constant volume depletion.

For well GCC-PR1 the z-factor behavior is shown in Figure 7. In the region above the dew point pressure, the z-factors determined from an untuned EOS show an average 3.4% deviation from laboratory observations. The results from the tuned EOS predict z-factors that average 3.9% lower than the experimental data. Below the dew point, the untuned EOS predictions deviate by 2.4% while the tuned EOS predictions deviate from observations by 2.2%.

The retrograde liquid curves for well GCC-PR1 are compared in Figure 8. Use of an EOS with default parameters predicts a dew point pressure that is 7.3% below the experimental result. The same EOS estimates liquid volumes that deviate from measured volumes by an average 36.4 %. A tuned EOS reduces the dew point pressure deviation to 1% and the average error associated with liquid volumes to approximately 11%.

Figure 9 illustrates the z-factor comparison for well GOC-CC7. The default EOS predicts z-factors that deviate from experimental values by approximately 3.2% over the entire range of measurements. A tuned EOS provides z-factor estimates that deviate by 7.6% in the region above the

dew point. Below the dew point pressure the z-factor predictions vary from the experimental values by an average 4.9%.

A comparison of retrograde liquid curves for well GOC-CC7 is shown in Figure 10. The un-tuned EOS predicts a dew point pressure that lies 22.5% below the measured value while estimating retrograde liquid volumes an average 22% above those observed in the laboratory. Tuning the EOS reduces the liquid volume deviation to approximately 6.5%; however, the error in the dew point estimate remains above acceptable levels at 8%.

For these gas condensate systems, large errors can be encountered when comparing estimated values to those observed in the laboratory. The magnitude of the error varies from well to well. Use of laboratory derived data to tune an EOS usually improves most estimates and reduces the overall errors; however, errors for specific parameters may increase substantially.

From a practical point of view, reliance on correlations and EOS calculations without experimental verification could lead to difficulties with production estimates, well operations, and economic evaluations. This can be seen with help from Figure 10 and the assumption that the only available information is provided by the default EOS.

The default EOS suggests that at pressures above 4669 psia the reservoir fluid remains undersaturated. This implies that above this pressure the produced gas contains its maximum condensate yield. However, actual production would observe a decline in the condensate yield at much higher pressures due to retrograde condensation in the reservoir. At 4669 psia, approximately 15% of the reservoir pore volume would be occupied by liquid, production would yield mostly gas, and economic returns may be less than optimal.

Conclusions

Experimental results from six wells were compared to predictions from several correlations and one equation of state. Generally, the results obtained from these computations vary widely in agreement when compared to laboratory data. The magnitudes of the errors vary from well to well and strongly depend on the correlation used and on the parameters used in the EOS calculations. Using laboratory data to tune an EOS improves the overall description of fluid properties, but errors for some calculated parameters may increase significantly. There does not appear to be a systematic method in choosing a correlation or EOS in order to insure accuracy in the predicted fluid properties.

In some cases, correlations can provide reliable estimates of fluid properties. This is often encountered in established fields where specific correlations were verified by laboratory analyses. However, the general usage of correlations and untuned EOS should be approached cautiously. The results obtained for any estimated parameters should be regarded only as guidelines in preparation for obtaining fluid samples. Currently, only laboratory measurements offer data with sufficient accuracy to form a basis for meaningful engineering and economic calculations.

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Table 1 - Oil System Parameters

Well	BOC-OW1	GOC-OW4	Units
Pres	5515	4115	psia
Tres	260	220	°F
GOR	121	600	Scf/STB
Oil	420	300	STB/d
Gas	51	180	Mscf/d
Oil grav. (1)	0.836	0.849	*****
Gas grav. (1)	0.707	0.732	*****
API @ 60 °F	36.5	35.1	°API
Psep	85	215	psia
Tsep	100	75	°F
Depth	12,500	8690	Feet

(1) Derived from laboratory flash liberation data.

Table 2 - Compositional Analysis for BOC-OW1

Component	Separator Liquid Mole %	Separator Gas Mole %	Wellstream Mole %
Hydrogen Sulfide	0.000	0.000	0.000
Carbon Dioxide	0.431	5.611	1.392
Nitrogen	0.030	3.682	0.707
Methane	2.382	83.785	17.477
Ethane	0.406	2.493	0.793
Propane	0.939	1.596	1.061
iso-Butane	0.621	0.460	0.591
n-Butane	1.819	0.905	1.650
iso-Pentane	1.586	0.337	1.354
n-Pentane	2.666	0.443	2.254
Hexanes	5.823	0.361	4.810
Heptanes plus	83.297	0.327	67.911
Totals	100.000	100.000	100.000

Table 3 - Compositional Analysis for GOC-OW4

Component	Reservoir Fluid Mole %
Hydrogen Sulfide	0.000
Carbon Dioxide	0.910
Nitrogen	0.160
Methane	36.470
Ethane	9.670
Propane	6.950
iso-Butane	1.440
n-Butane	3.930
iso-Pentane	1.440
n-Pentane	1.410
Hexanes	4.330
Heptanes plus	33.290
Totals	100.000

Table 4 - Correlation Comparison for Oil Systems

Correlation	BOC- OW1		GOC- OW4	
	Bubble Point (psia)	Difference (%)	Bubble Point (psia)	Difference (%)
Standing	727	-29.1	2728	3.5
Lasater	915	-10.7	3119	18.4
Vasquez & Beggs	802	-21.8	2893	9.8
AI - Marhoun	1015	-1.0	2785	5.7
P-R EOS (untuned)	1058	3.2	2426	-7.9
Experimental	1025	*****	2635	*****

Table 5 - Condensate Systems Parameters

Well	GCC-PR1	GOC-CC7	COG-Z1	POC-M4	Units
Pres	10,940	7015	6788	9354	psia
Tres	290	256	229	297	°F
GOR	12,420	4697	8235	10,398	Scf/STB
Condensate	94	185	85	467	STB/d
Gas	1,168	869	700	4858	Mscf/d
Oil grav. (1)	0.744	***	0.776	0.681	*****
Gas grav. (1)	0.699	0.699	0.789	0.637	*****
API @ 60 °F	54.3	46.5	56	50	°API
Psep	925/165	455	559/52	1,325	psia
Tsep	113/80	87	90/70	107	°F
Depth	12,000	11,300	8700	11,700	Feet

(1) Derived from laboratory flash liberation data.

Table 6 - Compositional Analysis for GCC-PR1, Condensate

Component	Separator Liquid Mole %	Separator Gas Mole %	Wellstream Mole %
Hydrogen Sulfide	0.000	0.000	0.000
Carbon Dioxide	1.114	2.360	2.237
Nitrogen	0.000	0.036	0.032
Methane	21.344	83.498	77.357
Ethane	7.419	8.040	7.979
Propane	7.670	3.396	3.818
iso-Butane	3.434	0.819	1.077
n-Butane	4.578	0.787	1.162
iso-Pentane	3.795	0.345	0.686
n-Pentane	2.814	0.213	0.470
Hexanes	5.379	0.214	0.724
Heptanes plus	42.453	0.292	4.458
Totals	100.000	100.000	100.000

Table 7 - Compositional Analysis for GOC-CC7, Condensate

Component	Separator Liquid Mole %	Separator Gas Mole %	Wellstream Mole %
Hydrogen Sulfide	0.000	0.000	0.000
Carbon Dioxide	0.000	0.010	0.010
Nitrogen	0.010	0.130	0.110
Methane	10.760	83.010	68.930
Ethane	6.170	9.230	8.630
Propane	8.810	4.500	5.340
iso-Butane	2.850	0.740	1.150
n-Butane	7.020	1.200	2.330
iso-Pentane	3.470	0.310	0.930
n-Pentane	3.310	0.250	0.850
Hexanes	8.030	0.210	1.730
Heptanes plus	49.570	0.410	9.990
Totals	100.000	100.000	100.000

Table 8 - Compositional Analysis for COG-Z1, Condensate

Component	Separator Liquid Mole %	Separator Gas Mole %	Wellstream Mole %
Hydrogen Sulfide	0.000	0.000	0.000
Carbon Dioxide	0.349	4.388	4.017
Nitrogen	0.000	0.101	0.092
Methane	2.747	74.904	68.283
Ethane	2.442	11.693	10.844
Propane	2.818	4.386	4.242
iso-Butane	1.380	1.016	1.050
n-Butane	2.321	1.158	1.265
iso-Pentane	2.808	0.671	0.867
n-Pentane	1.904	0.364	0.505
Hexanes	5.575	0.473	0.941
Heptanes plus	77.656	0.846	7.894
Totals	100.000	100.000	100.000

Table 9 - Compositional Analysis for POC-M4, Condensate

Component	Separator Liquid Mole %	Separator Gas Mole %	Wellstream Mole %
Hydrogen Sulfide	0.000	0.001	0.001
Carbon Dioxide	0.046	0.125	0.116
Nitrogen	0.030	0.140	0.128
Methane	33.364	91.829	85.345
Ethane	4.715	3.966	4.049
Propane	3.965	1.486	1.761
iso-Butane	3.676	0.812	1.130
n-Butane	3.441	0.573	0.891
iso-Pentane	2.475	0.249	0.496
n-Pentane	2.732	0.207	0.487
Hexanes	4.363	0.216	0.676
Heptanes plus	41.193	0.396	4.920
Totals	100.000	100.000	100.000

Table 10 - Correlation Comparison for Gas Condensates

Well	Nemeth & Kennedy		E O S		Actual
	Dew Point (psia)	Difference (%)	Dew Point (psia)	Difference (%)	Dew Point (psia)
GCC - PR1	4269	-1.3	4008	-7.3	4325
GOC - CC7	5121	-15.0	4669	-22.5	6025
COG - Z1	5611	20.6	5922	27.2	4654
POC - M4	6626	11.6	6817	14.8	5937

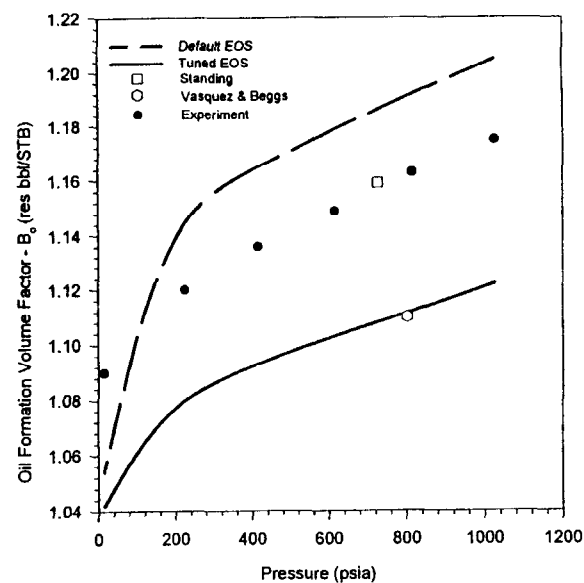
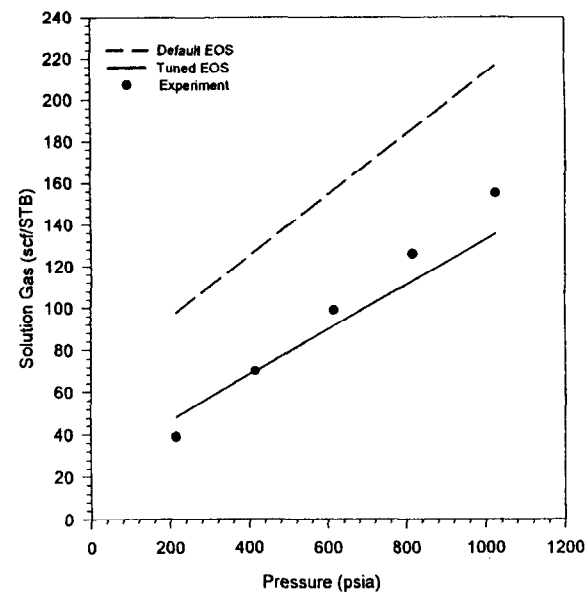
Figure 1 - Oil Formation Volume Factor, B_o , Dependence on Pressure During Differential Liberation for Well BOC-OW1

Figure 2 - GOR Dependence on Pressure During Differential Liberation for Well BOC-OW1

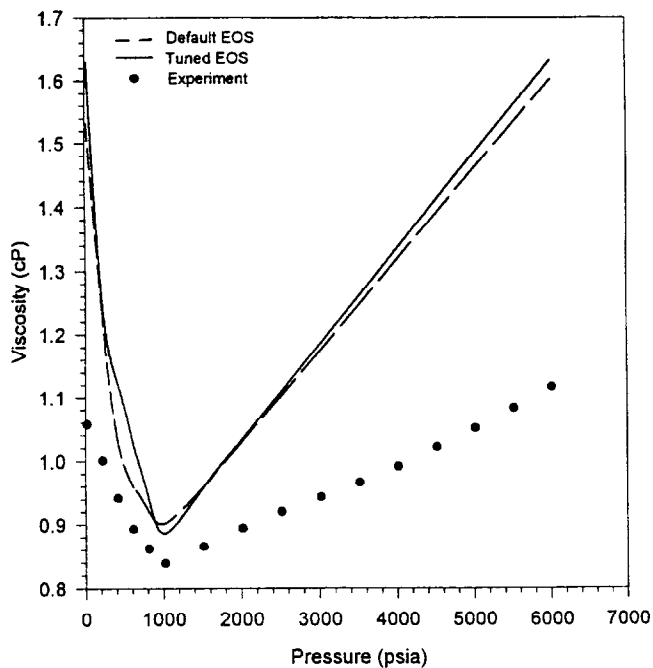


Figure 3 - Comparison of Calculated Viscosity Using EOS with Laboratory Measurements for Well BOC-OW1

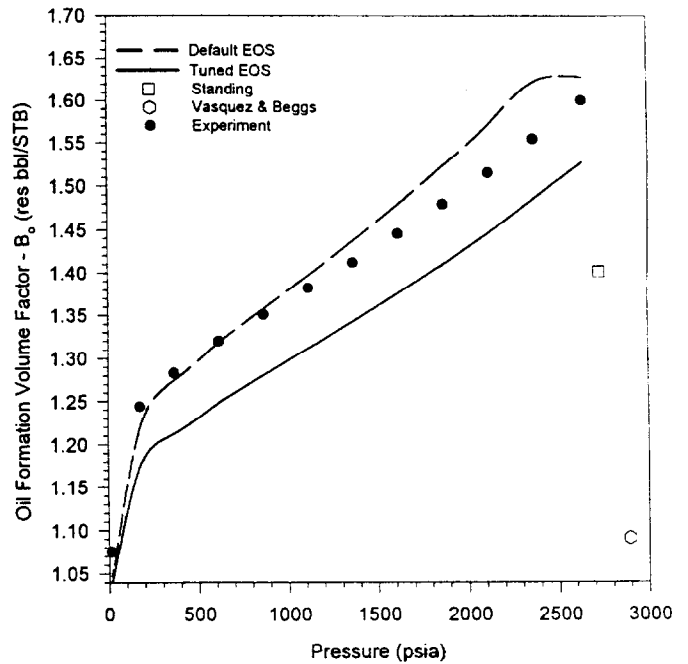


Figure 4 - Oil Formation Volume Factor, B_o , Dependence on Pressure During Differential Liberation for Well GOC-OW4

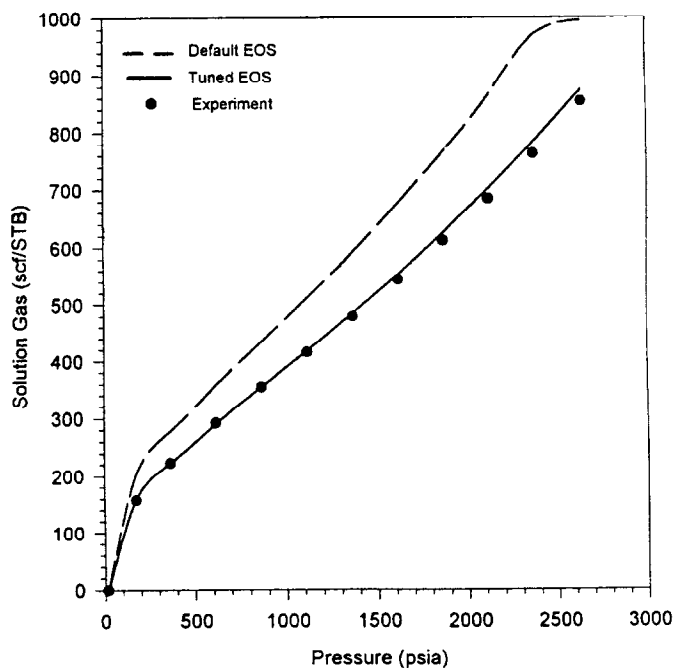


Figure 5 - GOR Dependence on Pressure During Differential Liberation for Well GOC-OW4

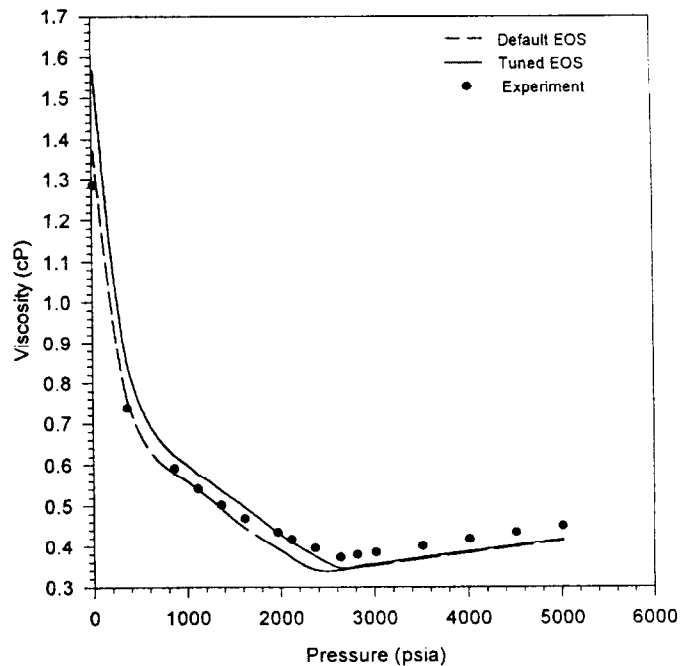


Figure 6 - Comparison of Calculated Viscosity Using EOS with Laboratory Measurements for Well GOC-OW4

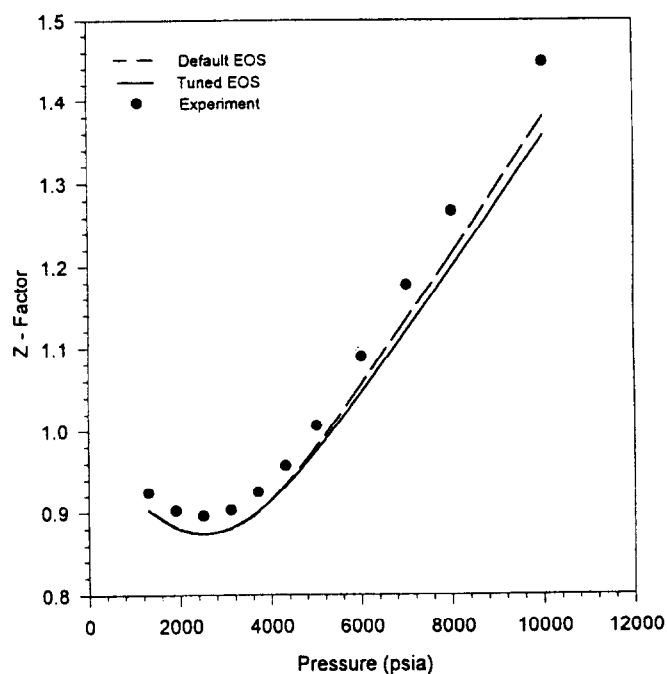


Figure 7 - Z-Factors as a Function of Pressure for Well GCC-PR1

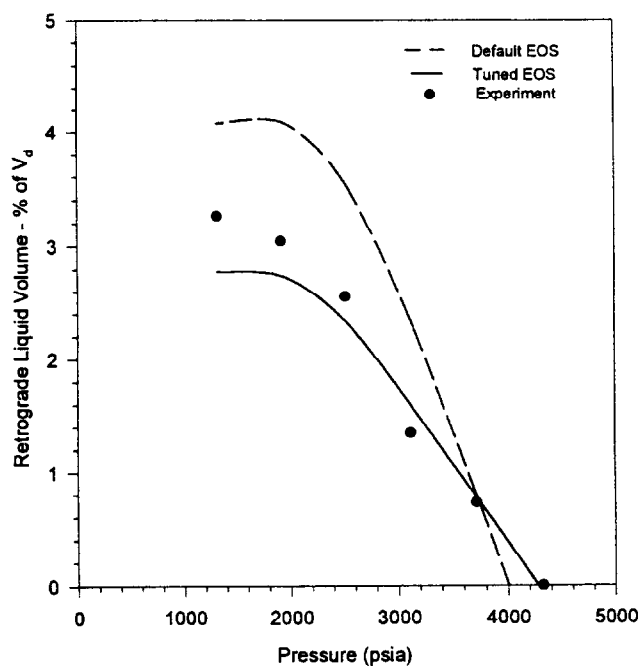


Figure 8 - Comparison of Calculated Retrograde Liquid Volumes Derived from EOS to Laboratory Measurements for GCC-PR1 During a Constant Volume Depletion

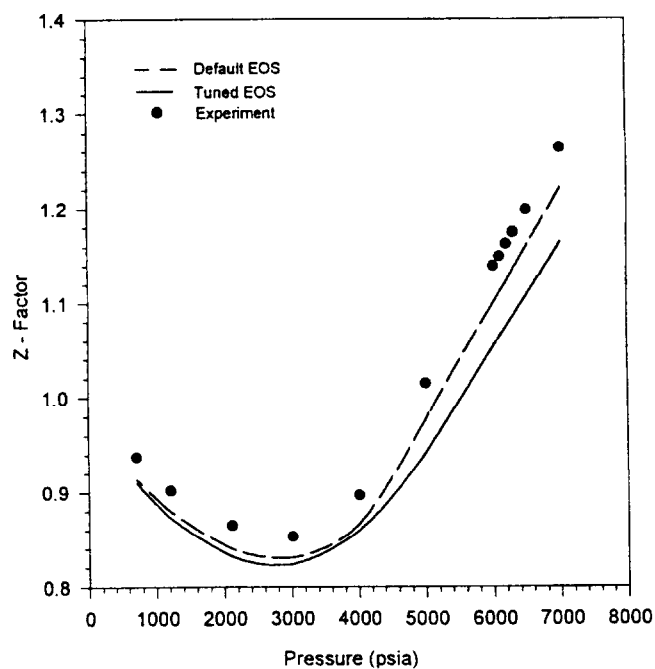


Figure 9 - Z-Factors as a Function of Pressure for Well GOC-CC7

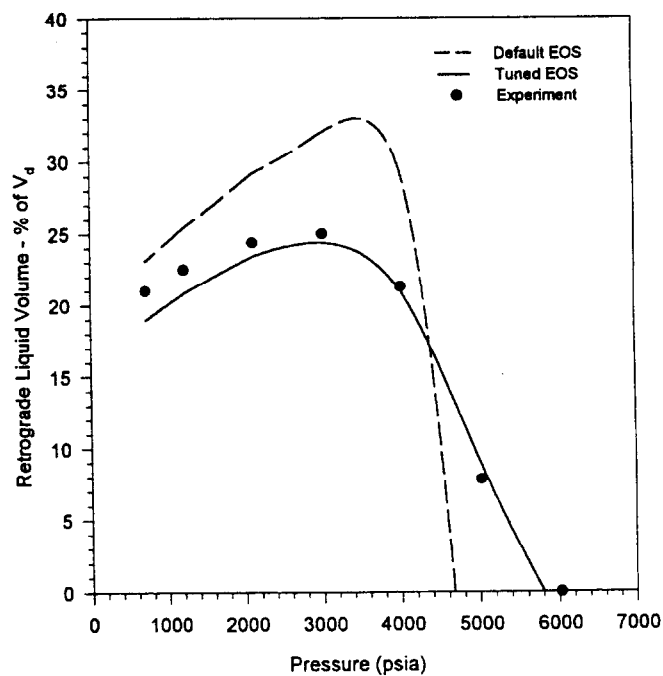


Figure 10 - Comparison of Calculated Retrograde Liquid Volumes Derived from EOS to Laboratory Measurements for GOC-CC7 During a Constant Volume Depletion