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Analysis of Effects of Temperature on Petrophysical Properties of Petroleum Reservoir Rocks and Fluids

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Abstract:-This work is basically a study of the variations of the petrophysical rocks and fluids properties with temperature. An experiment was carried out using quartz sandstone core samples to investigate the temperature effect on its permeability. The variations with temperature were calculated using published correlations at different reservoir temperature from a particular field data. The results were then used to generate graphs as a function of temperature for each property. Conclusive remarks on the observed trends are also presented.

Keywords:-**Petrophysics, Rock and Fluid, Temperature, Reservoir.**

I. INTRODUCTION

Temperature, as described in the oxford advanced dictionary is the degree of hotness or coldness of a place, thing or a system. Simple experiments, experience and judgments tell us that any chemical mixture of naturally occurring hydrocarbon becomes more volatile as its temperature is increased. Ultimately, when the temperature is great enough, a liquid will boil and begins to change into vapour. If such an experiment is carried out in a laboratory and the quantity of liquid and vapour present in a closed system as pressure and temperature are varied, it results in a pressure-volume diagram which illustrates how the petrophysical properties of reservoir fluids varies with respect to pressure and temperature.

As temperature and pressure increases, properties like viscosity, liquid density etc., generally decrease while properties like vapour density, viscosity, etc., generally increases. Thus, the difference in physical properties of the coexisting phases decrease. These changes continue as the temperature and pressure are raised until a point is reached where the properties of the equilibrium vapour and liquid becomes equal. The temperature, pressure and volume at this point are known as the critical values for that species and are useful in correlating physical properties of reservoir fluids.

The analysis of the effect of temperature on the petrophysical properties of rocks and fluids requires knowledge and understanding of these properties of reservoir rocks and fluids and the variations of these properties during reservoir exploitation.

A. Definition and Characteristics of Petrophysical Properties of Reservoir Rocks

1)Porosity: Porosity is a total measure of the space in a reservoir rock which is not occupied by the solid framework of the rock. It is defined as the fraction of the bulk volume of the rock not occupied by solids. Because it is an indirect measure of the volume of fluids and the storage capacity of the rock, two (2) types of porosity must be mentioned which are the total porosity and the effective porosity. The total porosity measures the porosity with respect to the total pore volume whereas the effective is only concerned with the porosity of the interconnected pore spaces.

2) Permeability: This is a measure of the ease of flow of a fluid through a porous medium. The permeability of an oil reservoir is as important as the porosity, for not only is the actual volume of oil in place important but also the actual rate at which the oil will flow through the reservoir. Strictly speaking, permeability is a proportionality constant in the fluid flow equation and anyone who pretends to understand the flow of fluid in porous media must comprehend this distinction. As described by Darcy, permeability is an intrinsic characteristic of a material that determines how easily a fluid can pass through it. The Darcy is the standard unit of measure for permeability.

Permeability is also measured in reference to a fluid phase. Such permeability is referred to as the effective permeability to that particular fluid. When the rock is 100% saturated with one fluid phase, it is the absolute permeability. The ratio of the effective to the absolute permeability is the relative permeability.

3) Fluid Saturation: The quantity of fluid within a rock, or the fraction of the pore space occupied by a particular fluid is known as the saturation of that fluid. It is defined as the fluid volume within the reservoir divided by the interconnected effective pore volume within which it resides. Like porosity, saturation is expressed as either a fraction or a percentage. It is important to note that saturation is a function of the pore volume, not bulk volume.

B. Definition and Characteristics of Petrophysical Properties of Reservoir fluids

1) Density: This is defined as the weight of oil per unit volume at some reference temperature and pressure, with units appropriate to its use.

2) Bubble Point Pressure: This is the pressure at which the first bubble of gas evolves as the pressure on the oil is decreased. This varies with temperature for a particular oil system.

3) Viscosity: This is a measure of the oil's resistance to flow and is defined as the ratio of the shearing stress to the rate of shear induced in the oil by the stress.

4) Shrinkage of oil: This is a measure of the change in oil volume which occurs as a result of changes in composition, pressure or temperature. For simplicity, this is usually expressed in the form of the Oil Formation Volume Factor, Bo, which can be defined as the volume occupied in the reservoir by one equivalent barrel of oil in the stock tank.

5) Solution Gas/Oil Ratio: This is the amount of gas that will evolve from the oil as the pressure is reduced to atmospheric from some higher pressure.

C. Variation of rock and fluid properties with temperature: Associated literature

In recent years, it has been demonstrated that for a single depositional rock unit with one or more void type, a representative rock or porosity data will exhibit a standard normal distribution. Likewise, corresponding permeability data will exhibit a log-normal distribution. Hence, a plot of the logarithm of permeability versus porosity for such a rock unit yields a straight line correlation. Also, a linear correlation of log-permeability versus porosity obtained from core analysis data can be used to construct a permeability profile from log-derived porosity data for uncored fields. It was also found out that subzoning of the reservoir rocks and replotting yields a set of linear relationships from the same data thereby enabling the stratigrapher to identify depositional units and yield a better description of the overall fluid flow characteristics of the reservoir.

It has also been noted in recent years that the so-called wettability of reservoir rocks and fluids has become an important concern that determines to a great extent the equilibrium saturation conditions existing in a virgin reservoir. Also, fluid displacement processes are not only influenced strongly by the wetting conditions within the rocks, but many so-called enhanced recovery methods depends on the presence of certain wetting conditions or are designed to alter prevailing conditions in a manner so as to improve the oil recovery characteristics.

An experimental study of quartz sandstones at reservoir conditions as a function of temperature by Aruna [1] who measured its physical properties with water, nitrogen, oil and 2-octonol showed strong decrease reversibly in the permeability when water was used. Rock permeability to the other fluids showed essentially no change with temperature. Similar results were found by Danesh et al [2] and Gobran et al [3] that temperature has no significant effect on the physical properties. Experiments by Piwinski and Netherton [4] have strong decrease in permeability during continuous flow of Salton Sea brines through sandstone cores at temperatures up to 194^{o}F (90^{o}C).

Empirical correlations were developed for predicting various fluid physical properties from limited data in cases where the variation of temperature with these properties is not available for production system calculations.

Several research workers have reported reductions in absolute permeability as temperature is increased. Afinogenov [5] found that absolute permeability decreased sharply by as much as 88% with increase in temperature. He however, suggested that this decrease could be accounted for by fluid property changes.

The Klinkenberg [6] correction essentially converts gas flow to equivalent liquid flow. In practice, some mineral constituents of the pore space may react to the type of flowing fluid. This is particularly true for clay minerals sensitive to water. The occurrence and effect of Illite in pores of North Sea reservoir rocks is particularly sensitive to fluid composition [7]. Other studies [8] have found that absolute permeability increases with increase in temperature.

With increasing temperature, Weinbrandt and Ramey [8] found that relative permeabilities to water were inconsistent. Increase in water permeability did not occur with increase in temperature for water saturations less than those corresponding to the residual oil saturation.

Edmondson [9] conducted water flooding experiments in the range of 75 – 500^{o}F and found a variation in relative permeability ratio as temperature increased. Nakornthap and Evans [10] have derived analytical expressions for relative permeability in terms of water saturation and showed that relative permeability to oil increases as temperature increases. They compared their results with a field example and found that the use of room temperature relative permeabilities in calculations would lead to pessimistic results.

Standing [11] presented an equation and monograph to estimate bubble point pressure greater than 1000 psia. This correlation was based on experiments that determined bubble point pressure of California oil system. The average error in these correlations when applied to the data used to develop the method was 4.8% and 106 psia. The ranges of data used to develop the method were also presented in his correlation. The gases evolved from the system used to develop the correlation contained essentially no Nitrogen or Hydrogen Sulphide. Some of the gases contained CO2, but in quantities less than 1 mole %. No attempt was made to characterize the tank oil other than by the API gravity. The value for gas gravity to be used is apparently the volume-weighted average of the gas from all stages of separation. The correlation applies to other oil systems as long as the compositional make-up of the gases and crude are similar to those used in developing the method.

Similarly, Lasater [12] in 1958 developed a correlation from experimental data points. This correlation was presented graphically in the form of two charts. Equations were fitted to these graphical correlations to enhance the use of this method with computers or calculators.

Vasquez and Beggs [13] used results from more than 600 oil systems to develop empirical correlations for several oil properties including bubble point pressure. This data encompassed very wide ranges of pressure, temperature, oil gravity and gas gravity and included approximately 6000 measured data points for solution gas/oil ratio (R_s), Oil formation volume factor (B_o) and oil viscosity (μ_o) at various temperatures and pressures.

Beal [14] presented a graphical correlation showing the effects of both oil gravity and temperature on dead-oil viscosity. This was developed form measurements made on oil samples. The relationship between viscosity, API gravity and temperature was given in the correlation. The decrease in the dead-oil viscosity as gas goes into solution was estimated and published by Chew and Connally [15] in 1959.

They also proposed an equation for correlating the dissolved gas. A method for calculating both dead-oil and saturated oil viscosity was presented by Beggs and Robinson [16] in 1975 which developed from more than 2000 measured data points using oil systems. Empirical correlations in the form of graphs were also presented by Baker and Swerdloff [17] where surface tension was correlated with temperature, API gravity and pressure.

II. METHODOLOGY

A. Experimental Procedure

The experiment involved continuous pore fluid flow at a confining pressure of 2940 psi and pore pressure of 1470 psi. A single-piston metering pump with gas-fluid separator in line to dampen pressure pulsation was used for pore fluid pumping. Fluid was preheated to within 5^{o}F (2^{o}C) of the experimental temperature before entering the Teflon sleeved core holder. Metering valves control outflow rate which was measured simultaneously using a ball float gauge. Differential pressure was measured using a differential transducer core 1.97m long by 1in in diameter of clean St. Peters Sandstone (>99% quartz) was used for the experiment.

No evidence of particle migration or clay plugging was observed in this rock. The pore fluid used was boiled de-ionized water. Typically, the sleeved core was:

i. Placed in the pressure vessel
ii. Evacuated for several hours
iii. Saturated at room temperature and then the permeability and porosity were measured.

Then the core was re-evacuated, the system heated to the desired experimental temperature (212^{o}F and 392^{o}F). The core was re-saturated at temperature and the physical properties were measured continuously.

B. Determination of Fluid Properties by Empirical Correlations

1) Oil Density Determination: Oil density is required at various pressures and at reservoir temperature for reservoir engineering calculations. The variation with temperature must be calculated for production system design calculations. The equation below is used to compute the density:

$$\rho_o = \frac{350\gamma_o + 0.0764\gamma_g R_s}{5.615 B_o} \qquad (1)$$

Where
ρ_o = oil density, lbm/cu.ft
γ_o = oil specific gravity
γ_g = oil specific gravity
R_s = Solution or dissolved gas, scf/STB
B_o = Oil FVF, bbl/STB
350 = Density of water @ standard conditions
0.0764 = Density of air at standard conditions, lbm/scf
5.615Conversion factor, cuft/bbl

2) Bubble-Point Pressure Correlations: Reservoir performance calculations require that the reservoir bubble point pressure be known. This is determined from a PVT analysis of a reservoir fluid sample or calculated by flash calculation procedure if the composition of the fluid is known. However, since this is unavailable, empirical correlations were developed which can be used to estimate bubble point or saturation pressure as a function of reservoir temperature, stock tank oil gravity, dissolved gas gravity and solution GOR at initial reservoir pressure. This work employs the Vasquez and Beggs [13] correlation given below:

$$P_b = \left[\frac{R_{sb}}{C_1\gamma_g \exp\left(\frac{C_3\gamma_{API}}{T_R+460}\right)}\right]^{\frac{1}{C_2}} \quad (2)$$

Where C_1, C_2 and C_3 are various constants
P_b = Bubble point pressure, psia
R_{sb} = Solution GOR at P_b, scf/STB
γ_g = Gas gravity
T_R = Temperature, ^oF
γ_{API} = Oil Gravity, ^oAPI

3) Solution GOR: Both reservoir engineering and production engineering calculations require estimates of the amount of dissolved gas in a solution at oil system pressure below bubble point pressure. The correlations presented earlier can be solved for any GOR and a value of R_s can be obtained at any pressure less than P_b. From the Vasquez and Beggs [13] correlation, the expression for R_s becomes:

$$R_s = C_1\gamma_g P^{C_2} \exp\left[\frac{C_3\gamma_{API}}{T+460}\right] \quad (3)$$

Where Rs = Gas in solution at P and T, scf/STB

*4) Oil Formation Volume Factor:*Empirical correlations are given which require values for solution GOR, R_s obtainable from previous methods presented. At pressures above bubble point, the oil is under-saturated and the liquid expands as pressure is reduced. Calculation of oil FVF thus requires a value for oil compressibility. Consequently, empirical correlations are presented for estimating the compressibility of an under-saturated system.

The correlation adopted in this work is that of Vasquez and Beggs [13] given below:

$$B_o = 1 + C_1R_s + C_2(T-60)\left(\frac{\gamma_{API}}{\gamma_{gc}}\right) + C_3R_s(T-60)\left(\frac{\gamma_{API}}{\gamma_{gc}}\right) \quad (4)$$

Where B_o = Oil FVF at P and T, bbl/STB
γ_{API} = Stock tank oil gravity, ^oAPI
γ_{gc} = Gas gravity corrected, air = 1

5) Oil Viscosity: As fluid flows through the production system, the temperature changes. This necessitates correlating the viscosity for temperature changes. This work adopts the correlation of Beggs and Robinson [16] for this. The defining relation is given below:

$$\mu_{od} = 10^x - 1.0 \quad (5)$$

Where
$X = T^{1.163}\exp[6.9824 - 0.04658\gamma_{API}]$
μ_{od} = Dead oil viscosity, cp
T = Temperature of interest, ^oF
γ_{API} = Stock tank oil gravity, ^oAPI

For correction of the effect of dissolved gases, they applied the following correction:

$$\mu_{os} = A\mu_{od}^B \quad (6)$$

Where μ_{os} Saturated oil viscosity

$$A = 10.715(R_s + 100)^{-0.515} \quad (7)$$

$$B = 5.44(R_s + 150)^{-0.338} \quad (8)$$

Where
R_s = Solution GOR, scf/STB

III. RESULTS AND DISCUSSION

A. Results

1) Experimental Results: A slight reddish decolouration 0.1 inch (0.25cm) thick was noticed on the input end of the core after the experiment. In the experiment carried out on the effect of temperature on the permeability of quartz sandstones, the permeability normalized to a reference room temperature value and decreased with time. After four hundred (400) minutes of flow, the pump was shut off. After five (5) minutes, more fluid flow was resumed just long enough for an additional measurement to be made ten (10) to twenty (20) seconds. This was repeated several times to determine permeability during the non-flow period. The apparent permeability of the rock increased to a steady level during this period, approximately 73% of K_o and 8% higher that the value measured during the flow of part of the experiments. Repeating the saturation procedure, the permeability at the same temperature was found to be 95% of K.

It is therefore concluded from the above that measured permeability is reversible with respect to flow and resaturation. Although experimental flow system built with stainless steel may show substantial flow dependent on decreases in permeability at elevated temperatures due to precipitation. Temperature, as such does not have a significant effect on the permeability of quartz sandstone.

2) Calculated Results: The tables below show the fluid properties calculated from the test result based on the models presented previously. The tables are used to prepare the ensuing plots.

Table 1: Variation of Oil Density with reservoir temperature

Temperature (^oF)	Density (lbm/cuft)
154	56.05
161	51.22
185	42.02
205	34.02
211	33.45

Table 2: Variation of Bubble Point Pressure with reservoir temperature

Temperature, ^oF	Bubble Point Pressure, P_b (psia)
154	1778.7
161	2537.8
185	3938.9
205	5422.5
211	5843.4

Table 3: Variation of Solution GOR with reservoir temperature

Temperature, ^oF	Gas Solubility, R_s (scf/STB)
154	426.8
161	589.3
185	1227
205	1552
211	1672

Table 4: Variation of Oil Formation Volume Factor with reservoir temperature

Temperature, ^oF	Oil FVF, B_o (bbl/STB)
154	1.122
161	1.215
185	1.615
205	1.953
211	2.063

Table 5: Variation of Oil viscosity with reservoir temperature

Temperature, ^oF	Oil Viscosity, μ_o (cp)
154	3.16
161	1.26
185	0.33
205	0.22
211	0.18

These tables are used to prepare the plots below.

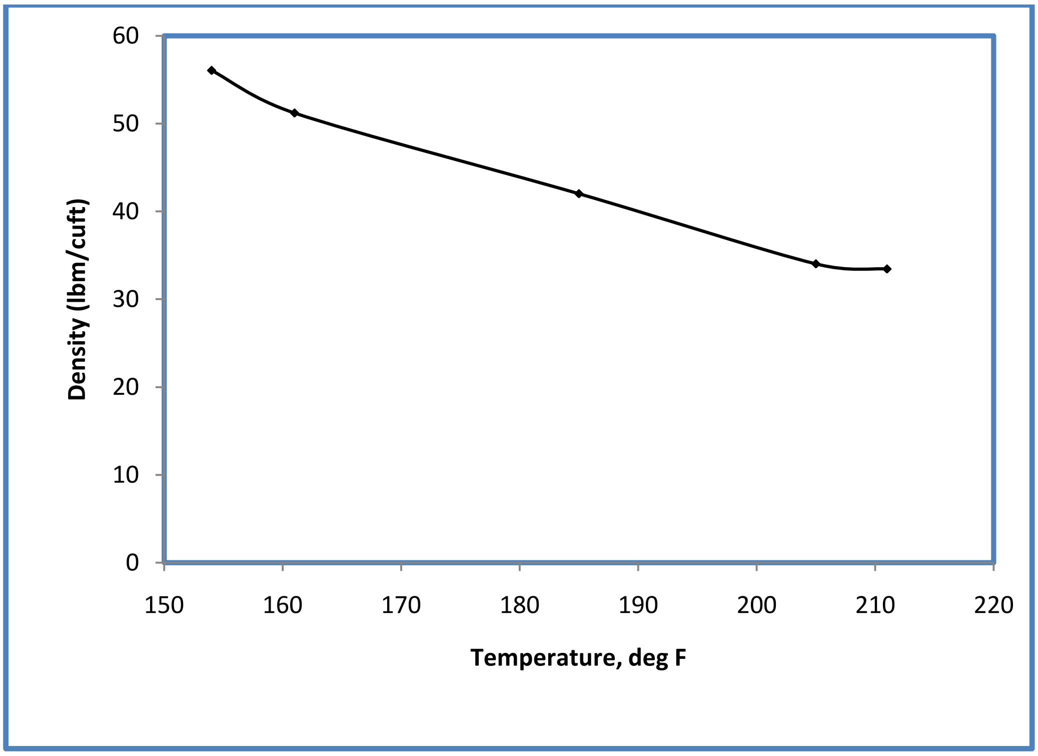

Fig. 1: Variation of fluid density with reservoir temperature

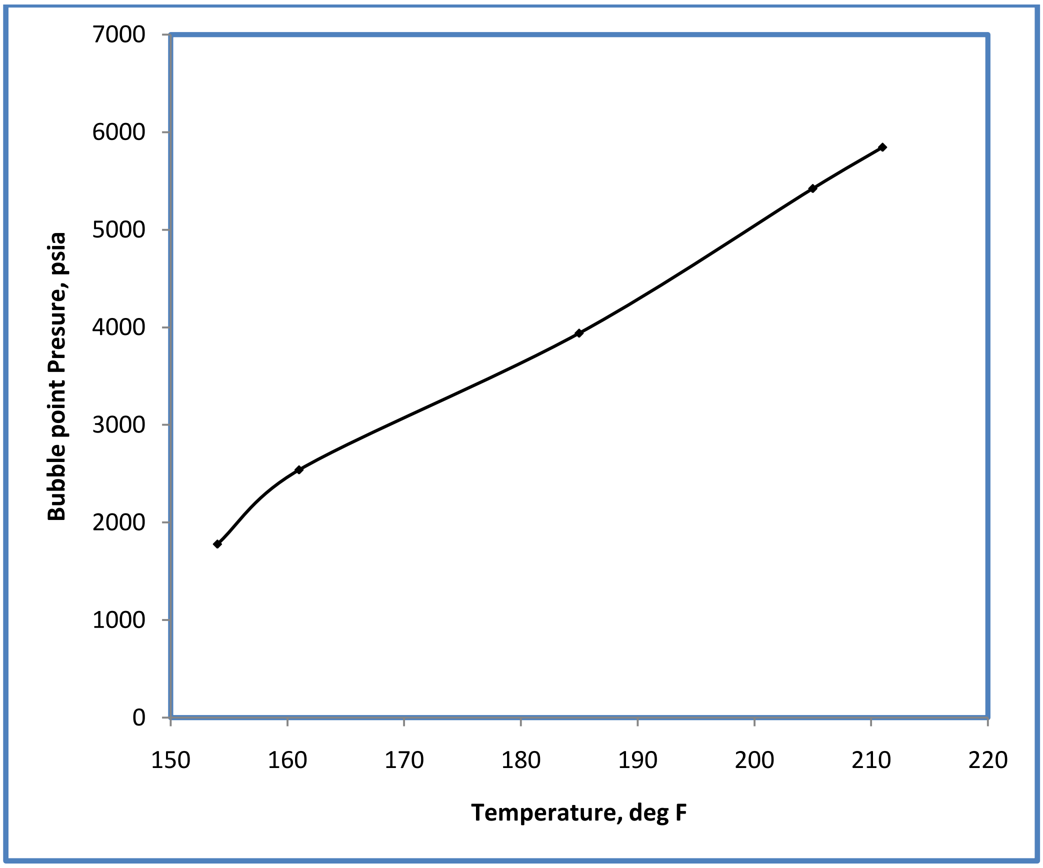

Fig. 2: Variation of Bubble point pressure with reservoir temperature

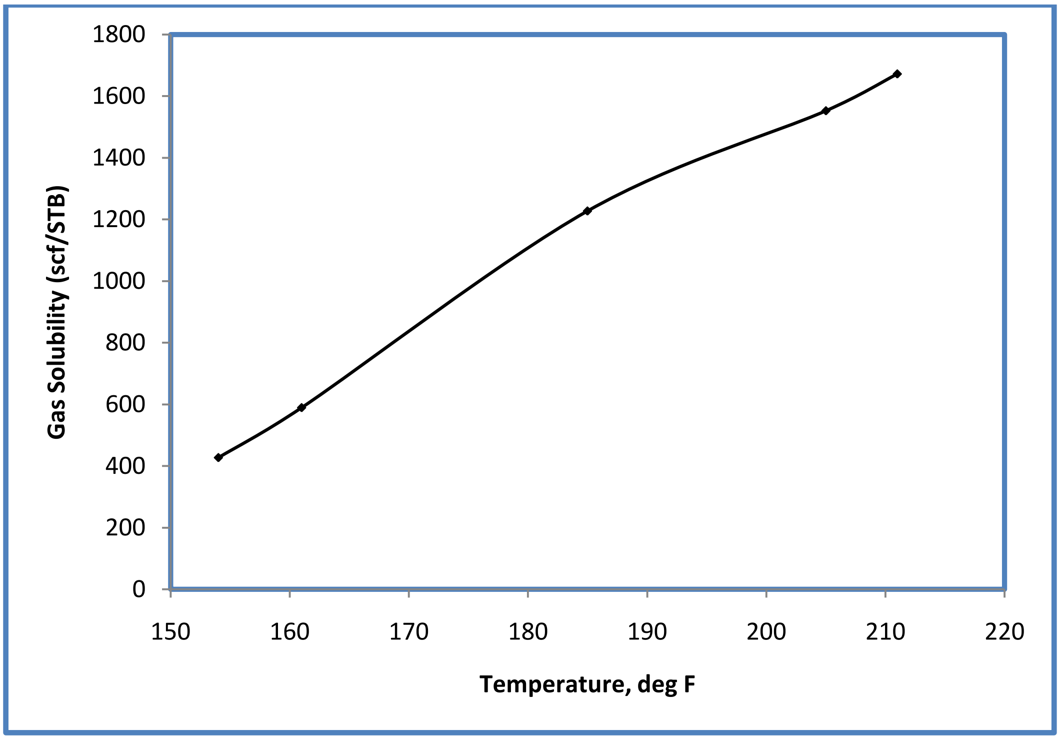

Fig. 3: Variation of gas solubility with reservoir temperature

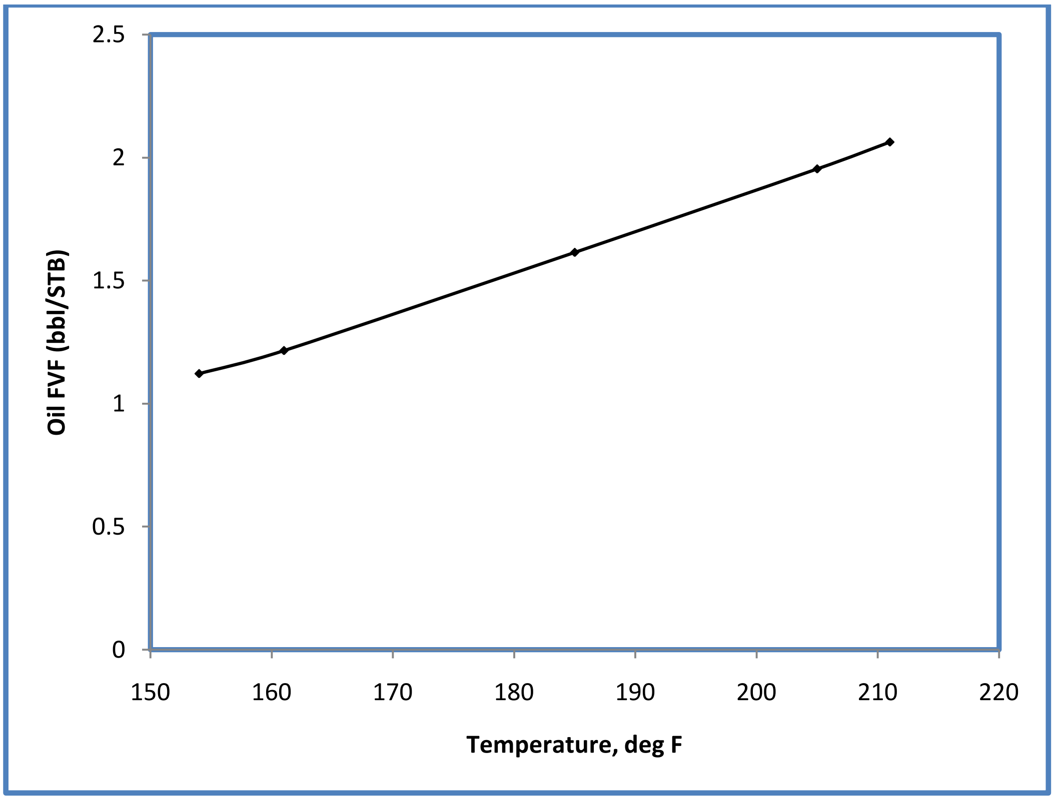

Fig. 4: Variation of Oil formation volume factor with reservoir temperature

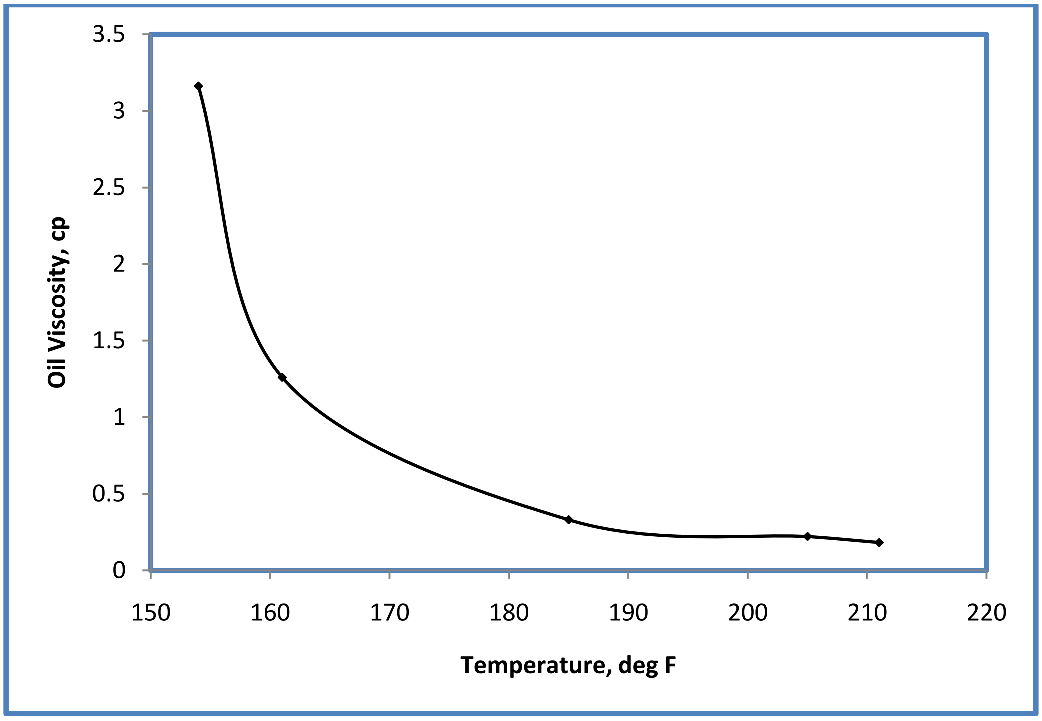

Fig. 5: Variation of Oil Viscosity with reservoir temperature

This figure shows the typical inverse variation of viscosity with temperature. The effect of viscosity reduction is a key factor in displacement mechanism in thermal recovery processes. When many crude oils are raised to a high temperature, the lighter component fractions tend to distil and segregate unless the pressure is constant.

IV. CONCLUSION

The variation of reservoir fluid properties with temperature has been presented. The study has revealed that rock properties of the study rock (ie., quartz) like permeability exhibit little or no variation with reservoir temperature. Reservoir fluid properties, on the other hand however, exhibit a strong dependence on reservoir temperature.

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