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Gas Viscosity Measurement and Evaluation for High Pressure and High Temperature Gas Reservoirs

Ijeoma Azubuike[1], Sunday Ikiensikimama[2], Oyinkepreye Orodu[3]
[1]World Bank African Center of Excellence for Oil Field Chemicals Research, Institute of Petroleum Studies, University of Port-Harcourt, Nigeria
[2]University of Port-Harcourt, Nigeria
[3]Covenant University, Ota, Nigeria
([1]ireneada@yahoo.com, [2]ikien2003@yahoo.com, [3]preye.d.orodu@gmail.com)

Abstract- Gas viscosity is an important fluid property in oil and gas engineering due to its impact on hydrocarbon production and transportation, reservoir recovery, fluid flow, deliverability, and well storage. Existing gas viscosity correlations were derived using measured data at low to moderate pressure and temperatures. No measured gas viscosities at high pressure high temperature (HPHT) using reservoir sample are currently available, and using the extrapolation approach is not reliable. Therefore, this research paper presents laboratory measurement of gas viscosity at HPHT and comparative study of some existing gas viscosity correlations using the measured data. The capillary electromagnetic viscometer was used to measure gas viscosity for pressures between 6,000 psia and 14,000 psia; and temperatures of 270 ^{o}F and 370 ^{o}F. The comparative study shows that the gas viscosity models commonly used in the industry are not very reliable at HPHT conditions. Ohirhian and Abu (2008) performed better than other evaluated correlations with the mean relative error of -5.22 and absolute error of 8.752 for the temperature of 270^{o}F while Dempsey (1965) came out the best for the temperature of 370^{o}F with mean relative error of -16.88 and 16.88 for absolute mean error. Cross plots showed the poor performance of the evaluated correlations using the measured data at HPHT conditions. From the analysis, the oil and gas industry needs new gas viscosity correlations that can predict gas viscosity at HPHT region.

Keywords- *gas viscosity, evaluation, pressure, temperature*

I. INTRODUCTION

The knowledge of the viscosity of hydrocarbon fluids is needed to study the dynamics or flow behavior of these mixtures through pipes, porous media, or more generally wherever transport of momentum occurs in fluid motion. The calculation of reserves in a gas reservoir or the determination of its performance at various stages requires the knowledge of the fluid's physical properties at elevated pressure and temperature. The principal among these properties is gas viscosity. Viscosity is a measure of a fluid's internal resistance to flow. It is expected to increase with both pressure and temperature, is usually several orders of magnitude smaller than that of oil or water; and therefore, gas is much more mobile in the reservoir than either oil or water. The most accurate way to quantify natural gas viscosity is to measure them in laboratory but accurate measurement is extremely difficult and expensive [1]. Because of the difficulties of viscosity measurements in laboratory, this parameter can be estimated from empirical correlations with low deviation.

Natural gas viscosity has been studied thoroughly by many authors ([2]; [3]; [4]; [5]; [6]; [7]; [8]; [9]; [1]; [10]) at low to moderate pressures and temperatures, yet there is still lack of detailed knowledge of gas viscosity at high pressures and high temperature (HPHT) in the petroleum industry.

[2] graphical correlations has been the most popular charts in the petroleum industry, because their chart set is perhaps the most complete, including the atmospheric pressure chart, the viscosity ratio charts and correcting charts for non-hydrocarbons. They used experimental technique of [11] to create the correlation, as a function of pseudo-reduced pressure, pseudo-reduced temperature and viscosity ratio. It was reported to have an average of 0.38 absolute errors. [2] Correlation is recommended to be used for gases with specific gravity between 0.55 and 1.22 and a temperature range between 100 and 300^{o}F.

[5] Regressed [2] data and obtained a mathematical expression which hold for the whole range of [2] chart.

[6] In 1966 presented a semi empirical relationship for calculating the viscosity of natural gases. The authors expressed the gas viscosity in terms of the reservoir temperature, gas density, and the molecular weight of the gas. The proposed correlation can predict viscosity value with a standard deviation of 2.7% and a maximum deviation of 8.99%. The correlation is less accurate for gases with higher specific gravities. The authors pointed out that the method cannot be used for sour gases. Their correlation was developed for pressure ranges between 100 and 8000 psi and temperature ranges between 100 and 340^{o}F.

[4] Developed a correlation for the viscosity of pure components such as argon, nitrogen, oxygen, carbon dioxide, sulphur dioxide, methane ethane, propane, butane and pentane.

They reported approximately 4% average absolute error and also stated that the correlation should only be applied for values of reduced density below 2.0.

[12] Proposed a convenient mathematical expression for calculating the viscosity of the natural gas at atmospheric pressure and reservoir temperature, μ_1. Also, he formulated the viscosity correction at one atmosphere for the content of H_2S, CO_2 and N_2. So by combining [12] and [5] correlation, the viscosity can be calculated.

[7] Developed a new correlation for hydrocarbon gas viscosity as a function of the gas viscosity at 1 atmosphere, gas density and temperature. He reported a 4.91% average absolute error for natural gas viscosity at pressure based on the database evaluated.

[13] Used a Cambridge viscosity SPL440 system to measure the viscosity of pure methane at pressures from 5,000 to 30,000 psi and temperatures from 100 to 400^{o}F. Based on the results from the measurements, [13] modified the correlation by [6]. The author then compared the modified [6] correlation to [14] values for pure gas. The results showed a very good match with the [14] values compared to the performance of the original correlation by [6]. However, Viswanathan's findings cannot be directly extrapolated to situations where impurities are present in the gas

[8] Developed a relationship for calculating the viscosity of natural gas under surface and reservoir condition. They obtained the correlation by the analysis of experimental pressure, volume and Temperature (PVT) data of Gas associated with Nigerian Crude oil. The authors went further to compare equation formulated with experimental PVT viscosity and then tested the general validity of the new equation by using it to solve two problems for which solutions by the complex charts of [2] were available.

[1] Showed in their work that small errors in gas viscosity affect the inflow performance relationship (IPR) curves and eventually change the reserves estimate for HPHT conditions in ways that drastically influence production forecasting. The authors also reported that through the work they did that none of the gas viscosity is reliable at HPHT condition.

[9] Presented a paper on the review of gas viscosity correlations that are available in the open literature, and discusses the validity of published gas viscosity correlations based on the range of applicability. The authors selected the falling body viscometer to measure gas viscosity for the pressure range of 3,000 to 24,500 psi and temperature range of 100 to 415^{o}F. Nitrogen was used to calibrate the instrument and to account for the fact that the concentrations of non-hydrocarbons are observed to increase dramatically in HPHT reservoirs. Viscosity is measured to reflect the fact that, at HPHT conditions, the reservoir fluids will be very lean gases, typically methane with some degree of impurity. The experiments showed that [6] correlation accurately estimates gas viscosity at low to moderate pressure and temperature, but does not provide a good match to gas viscosity at HPHT conditions.

[10] Presented work on the evaluation of gas viscosity correlations for the Niger Delta gas reservoirs. They evaluated their correlations based on the statistical analysis of percentage mean relative error, percentage absolute error, standard deviation of the mean relative error, absolute error and the coefficient of correlation. 319 data sets obtained from Niger Delta gas reservoirs were used for the analysis. From the statistical analysis result, the authors reported that [5] correlation ranked the best with the numerical value of 0.705 and also with the best performance plot. Charts of Viscosity against Pseudo Reduced Pressure and Temperature as well as Viscosity Ratio versus Pseudo Reduced Pressure and Temperature were also developed based on [5] correlation for Niger Delta region. They stated that their work is valid for data range of $1.4 \geq T_r \geq 1.90$ and $0.2 \geq P_r \geq 10.80$.

Having gone through the literature review, it can be observed that the data range used in the development and evaluation of gas viscosity are mainly based on low to moderate data base but very little are done for extreme conditions.. The need to understand and be able to predict gas viscosity at HPHT has become increasingly important as exploration moved to deeper formations where HPHT conditions are more likely to exist. High pressure and High Temperature (HPHT) gas reservoirs are defined as reservoirs having pressure greater than 10,000 psia and temperature over 300^o F [1]. Therefore, this paper presents the measurement of gas viscosity at HPHT and the evaluation of the existing correlations for these extreme conditions.

II. MEASUREMENT OF GAS VISCOSITY

The Cambridge Electromagnetic Viscometer was used for the measurement of gas viscosity**.** Electromagnetic Viscometer (EMV) System is based on the Cambridge Viscosity SPL440 sensor and the VP2000 viscometer controller. The SPL440 sensor is installed in a dedicated oven, permitting operation from just below ambient to its maximum operating temperature of 374 °F. The cylindrical viscosity sensor is mounted in a cradle that allows it to be orientated in four fixed positions for loading, operating, and torque opening/closure of the removable end of the sensor. The oven for this EMV system has been enlarged to accommodate a Degasser Fitting on the top of the EMV cell in place of the standard adapter. A system of three valves mounted inside the oven, but operated externally; allow the sample to be charged to the sensor. An in-line filter in the oven on the inlet side of the system removes particulates which could interfere with the measurements. A pressure transmitter, mounted just outside the oven, monitors the pressure.

The pressure transmitter is mounted above an external bleed/purge valve which allows the dead-space up to the transmitter body to be cleaned between analyses to minimize risk of sample carry-over. The pressure rating of the system is dependent on the weakest link of the installed components. Three (3) pressure ranges are available, 10,000, 15,000, or 20,000 psi. The SPL440 sensor is rated to 20,000 psig. The oven is mounted on the top of a modular, roll around aluminum framework which also supports the VP2000 control box and the CLI built Control Box. The VP2000 control box controls the piston movement inside the SPL440 as well as monitoring the internal SPL440 sensor. It holds the calibration data for all the supplied sinkers and uses these data to produce a raw viscosity figure. The raw viscosity figure is subject to correction for pressure and temperature distortion effects on the piston and measurement tube.

The RS232 connection inside the VP2000 box is connected through to the front panel of the CLI EMV Control Box to allow logging or setup operations to be performed. This system also has an RS232 connector on the front panel to allow communication with the pressure display. A LabVIEW™ pressure logger application is provided on the DVD in the documentation folder.

A representative of natural gas reservoir fluid samples were collected from the extreme high pressure gas reservoirs located in Niger Delta of Nigeria. The gas viscosity was measured using electromagnetic viscometer for the reservoir bottom hole samples pressures of 6000psia to 14,000psia and temperature of 270°F and 370 °F. After measuring the viscosity at 370 °F, the samples were cooled to 270°F and the experiment was repeated at that lower temperature for the various pressure ranges studied. Table 1 shows the composition of the samples used.

TABLE I. COMPOSITION OF THE GAS MIXTURES

Composition	Sample 1	Sample 2
C_1	90.05	90.44
C_2	4.07	4.06
C_3	1.29	1.29
$i\text{-}C_4$	0.29	0.29
$n\text{-}C_4$	0.31	0.41
$i\text{-}C_5$	0.51	0.09
$n\text{-}C_6$	0.10	0.08
C_7+	0.25	0.14
N_2	0.13	0.14
CO_2	3.21	3.00

III. RESULTS AND DISCUSSION

A. Effect of Pressure and Temperature on Measured Gas Viscosity

The effects of both high temperature and pressure on gas viscosity for the samples are shown in Figs. 1 and 2. It was also observed that the impacts of temperature on gas viscosity in the high pressure and at temperatures of 270°F are much higher than those at 370°F. The result indicates that as temperature increases the gas viscosity decreases.

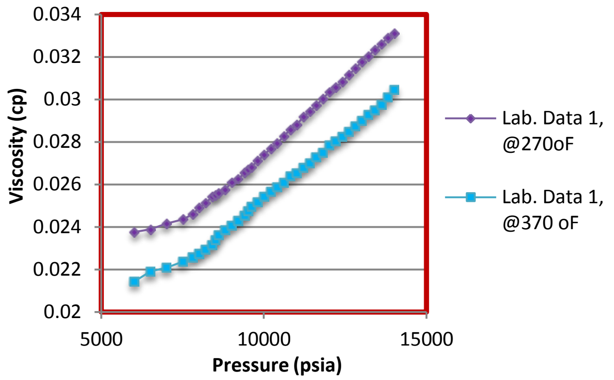

Figure 1. Measured gas viscosity for gas sample- 1 at 270°F and 370°F

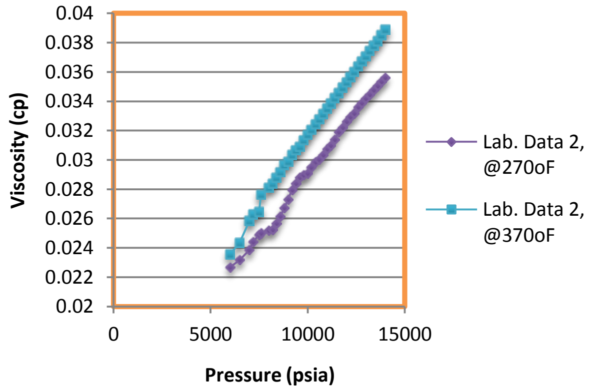

Figure 2. Measured gas viscosity for gas sample- 2 at 270°F and 370°F

B. Analysis of Existing Correlations with Measured Data

The laboratory measured gas viscosity data at HPHT were assessed to ascertain the accuracy of some selected correlations as applied to natural gas. The correlations evaluated are: [6]; [5]; [8]; [3] and [13]. These correlations were carefully selected, having been developed specifically for the prediction of natural gas viscosity. [2] Correlation was used to correct for the presence of impurities.

- Accuracy of Empirical Models: Gas Samples at 270°F and 370°F

The accuracy of ([6]; [5]; [8]; [3], [13]) empirical correlations was assessed for estimating gas viscosity for gas Sample 1. Fig. 3 compares the selected gas viscosity models with the measured data at 270°F for the entire pressure range studied; similarly Fig. 4 shows models comparison at 370°F. [3] And [13] were also among the correlation studied but their error margins are very high therefore, their plots were dropped from the figures. It can be observed from the charts that almost all the correlations studied overestimated the measured gas viscosity over the entire pressure range evaluated in this study with [8] coming closer to the measured data at very high pressure (Fig. 3).

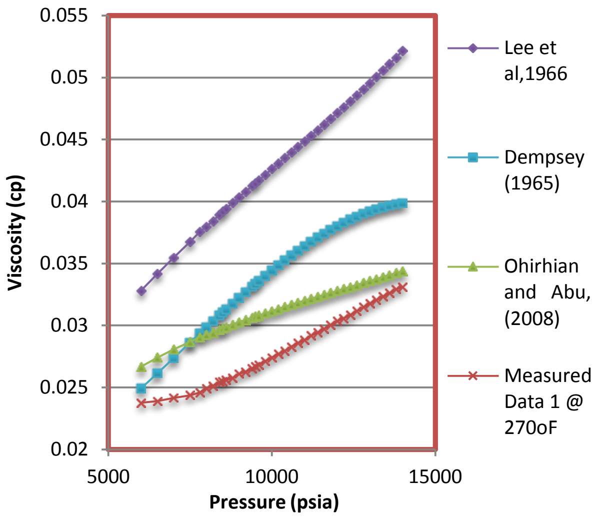

Figure 3. Gas Viscosity against Pressure at 270^{o}F for gas Sample- 1

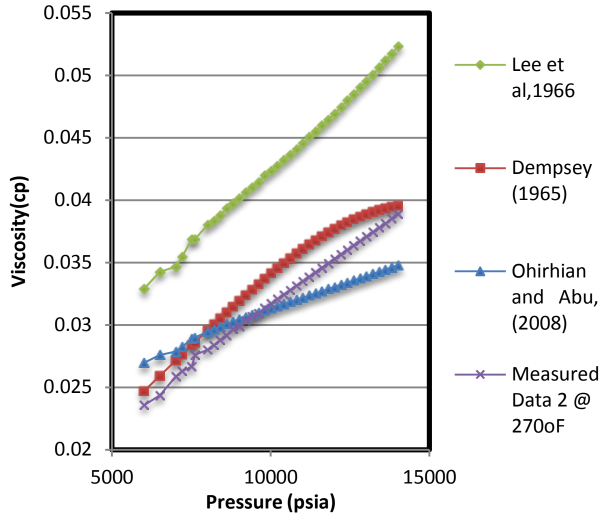

Figure 5. Gas Viscosity against Pressure at 270^{o}F for Sample- 2

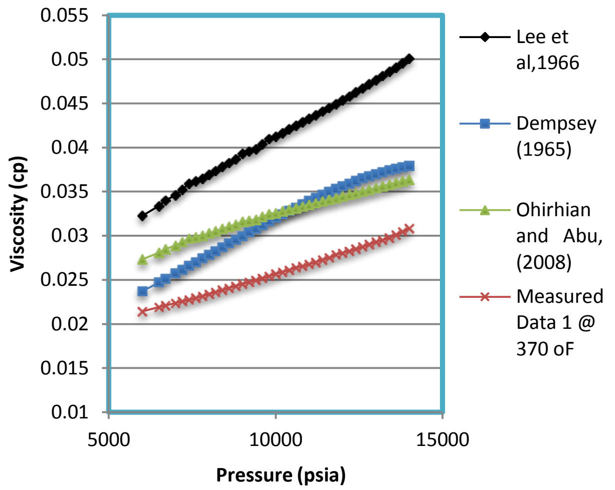

Figure 4. Gas Viscosity against Pressure at 370^{o}F for Sample- 1

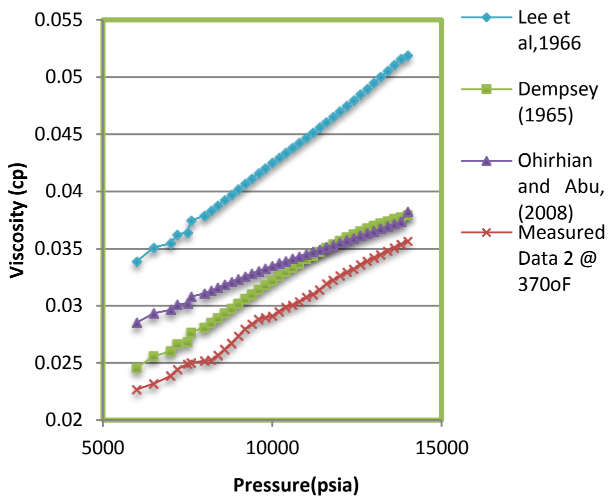

Figure 6. Gas Viscosity against Pressure at 370^{o}F for Sample -2

Figs. 5 and 6 compares gas viscosity calculated using some of the correlations with the measured data for the second sample at 270^{o}F and 370^{o}F. The same data trend was also observed as shown in Figs. 3 and 4. The difference between the computed and measured gas viscosity are greater, especially in the high-pressure range.

C. Statistical Comparison

The results of the assessment as presented in Figs. 7 and 8 are the plots of mean relative and absolute error showing the natural gas viscosity measured at 270^{o}F and 370^{o}F. Comparing Figs. 7 and 8, it can be found that the total mean error for the 370^{o}F cases and for [8] and [5] are more than two times greater than those for 270^{o}F, expect for [6] which generally performed badly for the data set studied. These differences suggest neither these correlations has been matched or turned to data at higher temperatures and seem to validate our concerns about extending the [2] correlation numerically to higher pressures and temperatures.

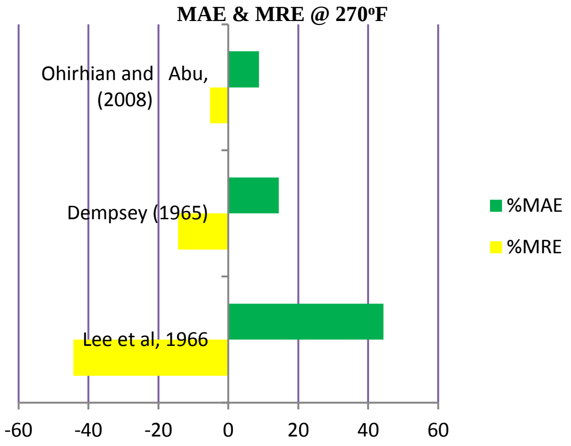

Figure 7. Mean Relative and Absolute Error at 270°F

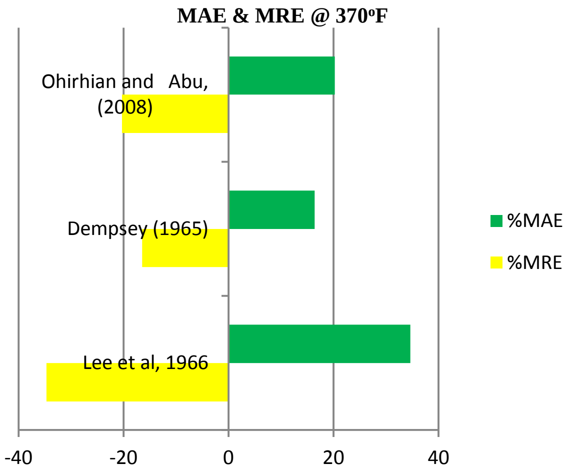

Figure 8. Mean Relative and Absolute Error at 370°F

D. *Cross Plots: Graphical Analysis*

Cross plots are plots of experimental values of natural gas viscosity against those estimated by the correlations. A perfect correlation is that plot that gives a straight line with a slope of 45°. Among all the correlations studied (Figs. 9 to 11), none of them gives a perfect slope of 45°. From the cross plots analysis, [8] performed better than others which also agreed with the previous evaluation.

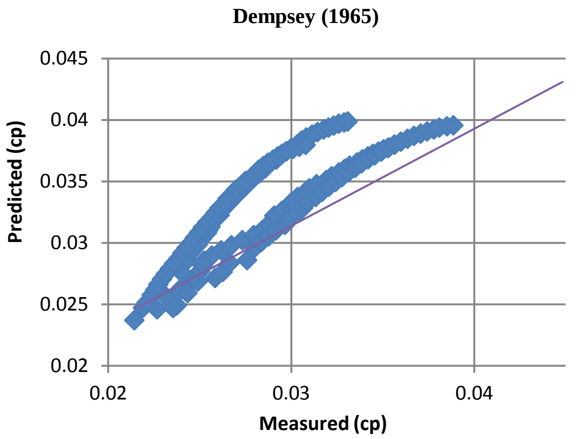

Figure 9. Cross Plot of predicted against Measured Viscosity for [5]

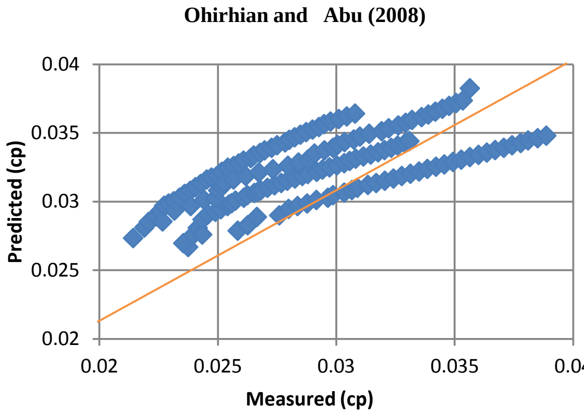

Figure 10. Cross Plot of predicted against Measured Viscosity for [8]

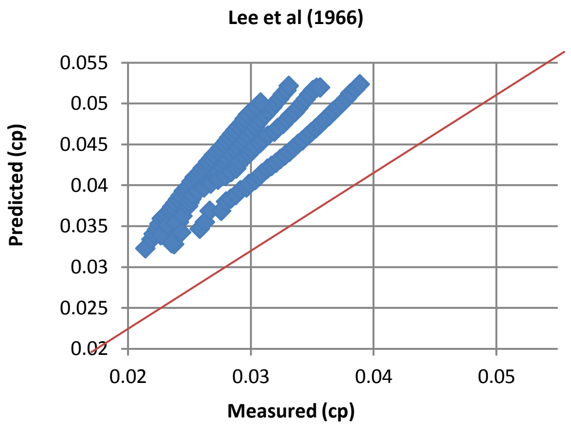

Figure 11. Cross Plot of predicted against Measured Viscosity for [6]

IV. CONCLUSION

The laboratory experiments for measuring gas viscosity and evaluation of some existing gas correlations has been presented. Gas viscosity correlations derived from data obtained at low to moderate pressures and temperatures cannot be confidently extrapolated to predict gas viscosity at HPHT conditions. [5] performed better than other evaluated correlations with the mean relative error of -16.88 and 16.88 absolute errors at 370^{o}F followed by [8] with a mean relative error of -20.27 and 20.27 absolute error. [8] came out best at 270^{o}F with a mean relative error of -5.22 and 8.752 for absolute mean error followed by [5] with a mean relative error -14.405 and absolute error of 14.405.The findings from this analysis show the need to measure the viscosity and develop correlations for HPHT conditions in order to ensure better reserves estimation.

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