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Validation of an Estimated Gas Condensate Reserve using Applied Uncertainty Analysis for the Condensate Reservoir Properties

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***Abstract*—**The Monte Carlo technique has been used quite extensively in the exploration business but to a much lesser degree in reserve estimation and production forecasting. Whether those forecasts or estimation are made with detailed reservoir simulation, enough production history data or decline curve techniques, there will be uncertainty in the forecasts. The Monte Carlo method performs random sampling from probability functions which describe the uncertainty of various input parameters in the OHIP (Original Hydrocarbon In Place) mathematical model. Therefore, use of the probabilistic approach is superior in green fields rather than brown fields because it captures the full range of reality and where models are not yet calibrated to dynamic data. In this study, a Monte Carlo simulation model integrated in MBAL software was run for a deep heterogeneous gas condensate field in Niger Delta. This field was separated into two major fault blocks. The study captures phase behavior of gas-condensate systems under isothermal depletion and also requirements for accurate estimation of reservoir properties of zones bearing gas-condensate systems.

The result from the simulation shows Monte Carlo probabilistic P50 case which are; 110Bscf of gas and 16mmstb of condensate were approximately 13Bscf and 3.7MMstb greater than volumetric estimate from an Independent 3rd party company. The indication is that the values of parameters that determine the P50 case where more optimistic than the P90 and P10 case due to the closeness of the figures of P50 case and those estimated by the other party. This method is not only more flexible in dealing with uncertainties but is also more advantageous for providing a better basis for investment decisions.

***Keywords*-**Probalistic,Uncertainty, Gas Condensate, Reserve, Distribution

I. Introduction

The process of estimating oil and gas reserves for a producing field continues throughout the life of the field but with several uncertainties which usually depends on reservoir type, source of reservoir energy, quantity and quality of the geological, engineering, and geophysical data, assumptions adopted when making the estimate, available technology, and the experience and knowledge of the evaluator.

The magnitude of these uncertainties however, decreases with time until the economic limit is reached and the ultimate recovery is realized.

In the early stages of development, reserves estimates are restricted to the analogy and volumetric calculations. The analogy method is applied by comparing factors for the analogous and current fields or wells. A close-to-abandonment analogous field is taken as an approximate to the current field. This method is most useful when running the economics on the current field; which is supposed to be an exploratory field. The volumetric method, on the other hand, entails determining the areal extent of the reservoir, the rock pore volume, and the fluid content within the pore volume. This provides an estimate of the amount of hydrocarbons-in-place. The ultimate recovery, then, can be estimated by using an appropriate recovery factor. Each of the factors used in the calculation above have inherent uncertainties that, when combined, cause significant uncertainties in the reserves estimate. As production and pressure data from a field become available, decline analysis and material balance calculations, become the predominant methods of calculating reserves. These methods greatly reduce the uncertainty in reserves estimates; however, during early depletion, caution should be exercised in using them.

Decline curve relationships are empirical, and rely on uniform, lengthy production periods. It is more suited to oil wells, which are usually produced against fixed bottom-hole pressures. In gas wells, however, wellhead back-pressures usually fluctuate, causing varying production trends and therefore, not as reliable. The most common decline curve relationship is the constant percentage decline (exponential). With more and more low productivity wells coming on stream, there is currently a swing toward decline rates proportional to production rates (hyperbolic and harmonic). Although some wells exhibit these trends, hyperbolic or harmonic decline extrapolations should only be used for these specific cases. Overexuberance in the use of hyperbolic or harmonic relationships can result in excessive reserves estimates.

Material balance calculation is an excellent tool for estimating gas reserves. If a reservoir comprises a closed system and contains single-phase gas, the pressure in the reservoir will decline proportionately to the amount of gas produced. Unfortunately, sometimes bottom water drive in gas reservoirs contributes to the depletion mechanism, altering the performance of the non-ideal gas law in the reservoir. Under these conditions, optimistic reserves estimates can result. When calculating reserves using any of the above methods, two calculation procedures may be used: deterministic and/or probabilistic. The deterministic method is by far the most common. The procedure is to select a single value for each parameter to input into an appropriate equation, to obtain a single answer. The probabilistic method, on the other hand, is more rigorous and less commonly used. This method utilizes a distribution curve for each parameter and, through the use of Monte Carlo Simulation; a distribution curve for the answer can be developed. Assuming good data, a lot of qualifying information can be derived from the resulting statistical calculations, such as the minimum and maximum values, the mean (average value), the median (middle value), the mode (most likely value), the standard deviation and the percentiles.

The probabilistic methods have several inherent problems. They are affected by all input parameters, including the most likely and maximum values for the parameters. In such methods, one cannot back calculate the input parameters associated with reserves. Only the end result is known but not the exact value of any input parameter. On the other hand, deterministic methods calculate reserve values that are more tangible and explainable. In these methods, all input parameters are exactly known; however, they may sometimes ignore the variability and uncertainty in the input data compared to the probabilistic methods which allow the incorporation of more variance in the data.

A comparison of the deterministic and probabilistic methods, however, can provide quality assurance for estimating hydrocarbon reserves; i.e. reserves are calculated both deterministically and probabilistically and the two values are compared. If the two values agree, then confidence on the calculated reserves is increased. If the two values are away different, the assumptions need to be reexamined [1]. For potential accumulations with limited information, the GIIP estimate may become difficult or very uncertain, in which case the volumetric-based estimation using probabilistic method(s) will be employed.

II. PETROLEUM RESERVES ESTIMATION METHODS

The more appropriate method will depend on the maturity of the project reservoir.

In most reserve estimation works, both static (deterministic) and dynamic (material balance and simulation) are used as complimentary measures at the later stage of the reservoir development to have a better picture of the reservoir and achieve field optimum development.

The simplest form of the equation for the deterministic volumetric method that assumes ideal case, homogenous, isotropic reservoir is;

$$G = \frac{43560\ (A)(h)(\frac{N}{G})(\emptyset)(1 - Sw)}{Bgi}$$

For non-homogenous and non-isotropic reservoirs, the real case when more wells have been drilled and contour maps can be prepared for each of the above parameters (i.e. gross isopach, net-to-gross,is0-porosity, iso-water saturation and hydrocarbon contact maps), volumetric computation is by numerical integration using the following form of the equation either in 2d or 3d models.

$$G.\mathrm{Mscf} = \sum_{j=1}^{n} \frac{(A_j)(h_{gj})(N/G)_j(\emptyset_j)(1 - S_{wj})}{B_{gi}}$$

In either deterministic volumetric case using these equations the petroleum engineer or geologist will determine a range of values or maps for each parameter: minimum, most likely and maximum such that estimates of the in-place volumes will be expressed as low, best and high cases.

In this Probabilistic method, the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

A calculation technique in probabilistic method is by Monte-Carlo simulation. [13] used Monte-Carlo technique to derive IIP, UR and RF values, such that a probability distribution for the results can be reported. For each reservoir in their input deck, the system performs the calculation one or several conforming to the distributions specified by the user.

Material balance method

For volumetric gas reservoir it can be derived easily that:

$$\frac{P}{Z} = \frac{P_i}{Z_i} - \frac{P_i}{Z_i}\left(\frac{G_p}{G}\right)$$

A plot of p/z versus Gp yields a straight line whose intercept on the x-axis equals the original gas in place. The literature is replete with information on characteristic shape of the plots for different reservoir drive mechanisms including over pressured reservoirs [14] [15].

For gas reservoirs with water influx, the MBE can be represented as

$$GBgj - (G - Gp)Bg = We - WpBw$$

[16] re-arranged this in the form of a straight line to make in-place volume determination easy as shown:

$$\frac{GpBg - WpBw}{Bg - Bgj} = G + Caq\frac{\emptyset\ (p,t)}{Bg - Bgj}$$

Where,

$W_e = C_{aq}\emptyset\ (p,t)$, Caq = aquifer constant and $\emptyset\ (p,t)$ = aquifer function which definition depend on type of aquifer. Various aquifer models have been offered by Fetkovich, Carter-Tracy and Hurst and van Everdingen.

III. RESERVES DETERMINATION USING PROBABILISTIC METHODS

The probabilistic method is more rigorous and less commonly used. This method utilizes a distribution curve for each parameter and, through the use of monte carlo simulation, a distribution curve for the answer can be developed. Glenn robinson came to the conclusion that oil and gas industry is directing itself towards higher risk ventures because conventional sources are becoming depleted.

A probability distribution accounts for the range of likelihoods of occurrence of possible values that a random variable might accomodate. Upon the nature of the random variable, probability distributions can be discrete or continuous. The random variable is represented by the horizontal scale along

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with unites and range of values. The likelihood of occurrence of the ranges of values is proportional to the height of the probability allocation.

Several special types of distributions are used in exploration risk analysis. However, the following listed specific distributions are the most commonly used.

Normal distribution usually represented by bell shape have been seen to be adopted for core porosity and percentages of abundant minerals in rocks.

Lognormal distribution is as the normal distribution a continuous probability distribution except that it is skewed in either direction. The skeweness describes a random variable that has a small chance of occurrence compared to the other direction of the shape. Core permeability and oil recovery in a given formation producing by a common reservoir drive are some examples that can be exhibited in such a distribution.

Uniform distribution is a continuous probability distribution that describes a random variable in which any numerical value has an equal chance of occurrence. It is unique in a sense that the mean value and the median value are concurrent and occur at the midpoint value of the random variable.

Triangular distribution as the names implies has the shape of a triangle. The triangle can be symmetrical or skewed in both directions and is completely defined by specifying the minimum, most likely, and maximum values of the random variables.

Binomial distribution is a discrete probability distribution which describes the probabilities of a given number of outcomes with a defined number of trials. It is commonly used in quality control work. It can be used under certain condition in the petroleum exploration context to compute the probabilities of a given number of discoveries in multilaterals well.

Multinomial distribution also a discrete distribution describes the bernoulli process as the number of occurrence can be called multinomial probability distribution. It considers only two possible outcomes.

Hyper geometric distribution is a discrete distribution which does not presume the independence of each single trial as that of the bernoulli process. It is handy in computing probabilities of various outcomes of a multi-well exploration as there are only a limited number of prospects available.

The main objectives of this study are:

[i] To illustrate reasonable and defendable projections to be used for reserves estimation

[ii] To adequately understand phase behavior of gas-condensate systems under isothermal depletion and also requirements for accurate estimation of reservoir properties of zones bearing gas-condensate systems

[iii] To employ Monte Carlo technique in estimating a gas condensate reserve from a field generated data.

[iv] To compare the HCIIP with generated probabilities/expectations.

The scope of the workdone as contained in this paper is as follows:

The model built was based upon the data provided by the client. Because these simulation models contain little or no history match data, the results from a single deterministic case was put in perspective of the entire range of likely outcomes (possible reserves and recoveries).

Details of the approach deployed to validate the already estimated gas condensate reserve are as described below:

IV. Data Organization

This condensate reservoir was found in the marine paralic zone (much of Agbada formation) with wells drilled up to a TD of 13500ft referenced to the ground level. The basic parameters used for the simulation runs are reservoir depth (ft), reservoir pressure (psia), reservoir temperature (^{0} f) all at GOC/GDT/GWC.

Table 1: Basic data used for the Monte Carlo simulation.

Geologic Zone	Depth (ft)	Pressure (psia)	Temperature (^{0} f)
Marine Paralic	13500	5900	240

V. Fluid Definition

On initializing the MBAL model, Retrograde Condensate is defined as the fluid type. The basic input data required by the black oil model in form of gas gravity, oil gravity and GOR (or CGR), are determined by flashing the fluid down to standard conditions through separator train.

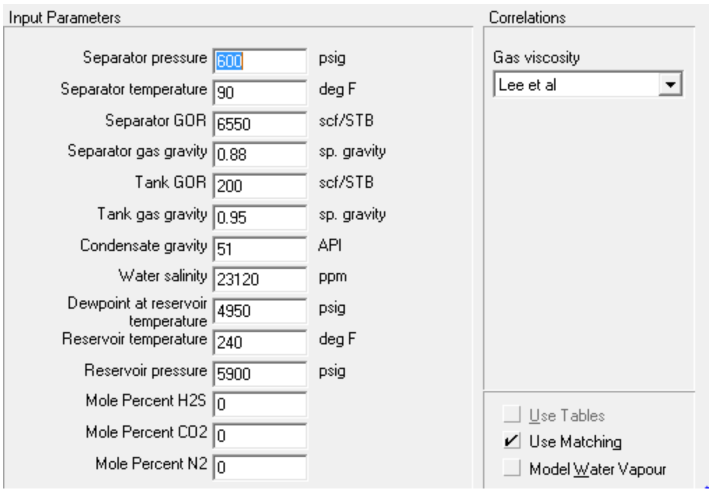

Figure 1.1: Input parameters on MBAL model for fluid definition.

VI. PVT Data/Matching

MBAL uses the Retrograde Condensate Black Oil model (modified). The regression allows the matching of PVT data

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to real data to be carried out. These models take into account liquid dropout at different pressures and temperatures

The data entered for matching was gotten from a CCE experiment conducted on the gas condensate fluid from ZZZ field at a temperature of 240^0 F in order to ensure mass balance consistency in the data.

Table 2: PVT data from CCE experiment.

Pressure psig	Dew point psig	CGR STB/MMscf	Vapourized CGR STB/MMscf	Z factor	Gas FVF ft3/scf	Gas Viscosity (cp)	Oil FVF RB/STB	Oil Viscosity (cp)
6010	4950	0	148.147	1.10781	0.00364	0.06230	0	0
5680	4950	0	148.147	1.06747	0.00371	0.05969	0	0
5350	4950	0	148.147	1.02736	0.00379	0.05699	0	0
4954	4950	0	148.147	0.97970	0.00390	0.05362	0	0
4822	4950	13.6203	135.849	0.96331	0.00394	0.05036	2.4489	0.14731
4558	4950	39.8231	112.402	0.93376	0.00404	0.04443	2.3453	0.15210
4294	4950	63.4817	91.5401	0.90862	0.00417	0.03936	2.2445	0.15720
4030	4950	84.5959	73.2611	0.88778	0.00434	0.03507	2.1468	0.16264
3502	4950	119.191	44.4423	0.85769	0.00483	0.02847	1.9602	0.17472
3172	4950	135.645	31.6627	0.84519	0.00525	0.02541	1.8499	0.18326
2908	4950	145.946	24.3318	0.83815	0.00568	0.02340	1.7653	0.19075
2644	4950	153.703	19.5688	0.83341	0.00621	0.02171	1.6839	0.19896
2380	4950	158.915	17.3701	0.83091	0.00687	0.02024	1.6058	0.20802
2050	4950	161.852	18.2225	0.83131	0.00797	0.01866	1.5131	0.22080
1786	4950	161.34	21.7809	0.83506	0.00918	0.01752	1.4430	0.23252
1522	4950	158.283	27.8932	0.84266	0.01086	0.01647	1.3765	0.24595
1258	4950	152.681	36.5578	0.85501	0.01330	0.01550	1.3138	0.26165
928	4950	142.102	50.9805	0.87836	0.01845	0.01437	1.2409	0.28586

The matching facility in MBAL software is used to adjust the empirical fluid property correlations to fit measured PVT laboratory data. Correlations are modified using a non-linear regression technique to best fit the measured data. A good PVT match if plotted will show reasonable agreement with the correlations (Lee et al) and thus, the fluid behavior can be predicted at each point. This PVT match is understood better from the following plots below:

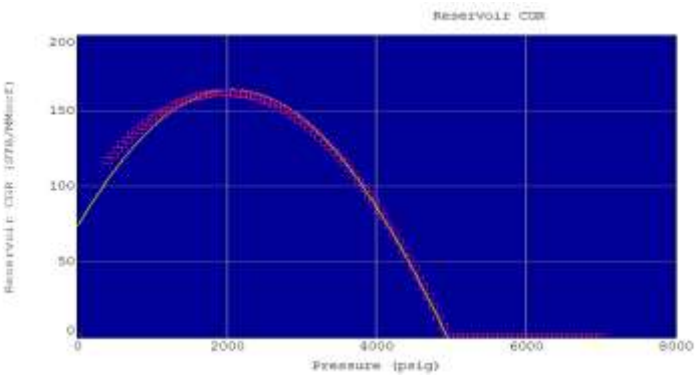

Figure 2.1: PVT and Lee et al correlation match for Condensate Gas Ratio

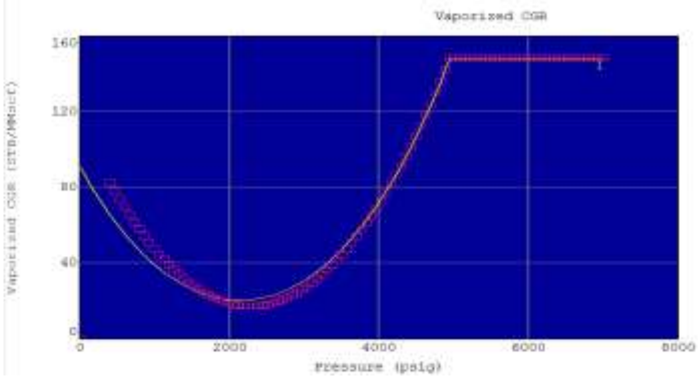

Figure 2.2: PVT and Lee et al correlation match for Vaporized Condensate Gas Ratio

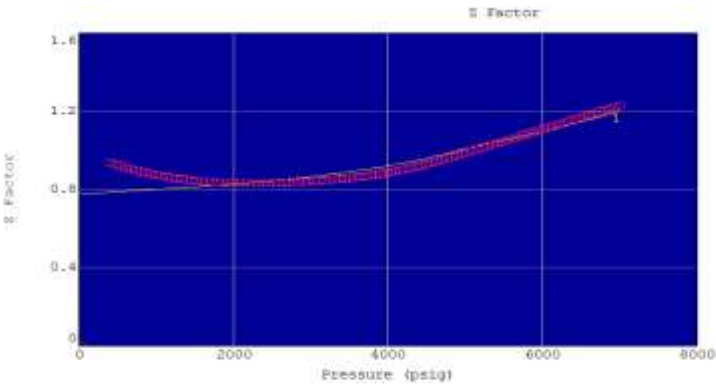

Figure 2.3: PVT and Lee et al correlation match for Z - Factor

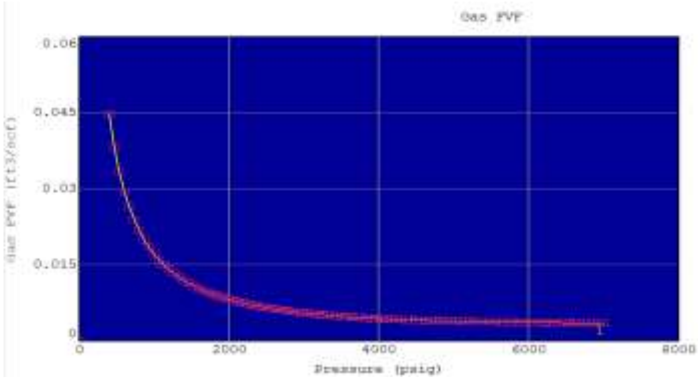

Figure 2.4: PVT and Lee et al correlation match for Gas Formation Volume Factor.

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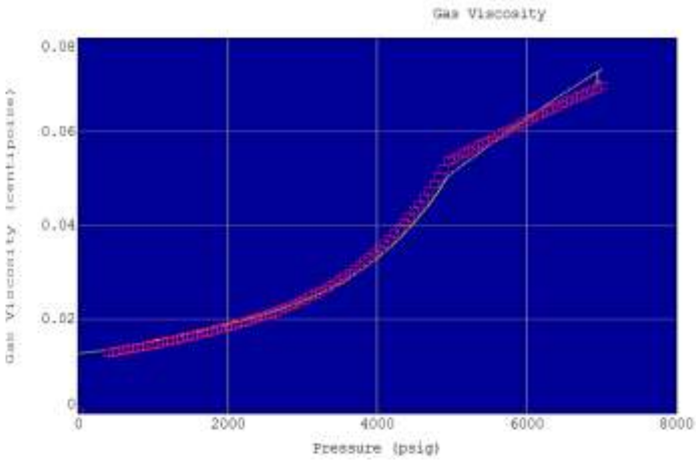

Figure 2.5: PVT and Lee et al correlation match for Gas Viscosity.

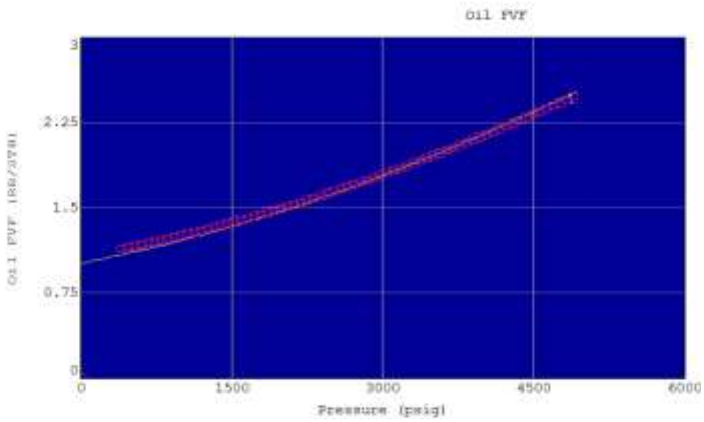

Figure 2.6: PVT and Lee et al correlation match for Oil (Condensate) Formation Volume Factor

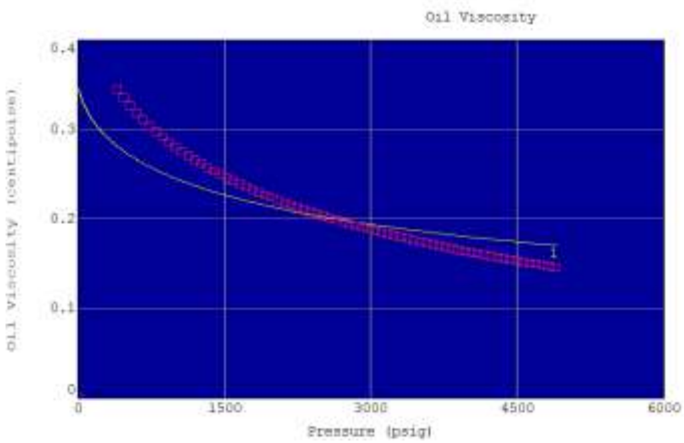

Figure 2.7: PVT and Lee et al correlation match for Condensate Viscosity

VII. RESERVE ESTIMATION

The Monte-Carlo technique is used to evaluate the hydrocarbons in place. Each of the parameters involved in the calculation of reserves; the PVT properties and pore volume are represented by statistical distributions. Depending on the number of cases (NC) chosen, the program generates a series of NC values of equal probability for each of the parameters used in the hydrocarbons in place calculation. The NC values of each parameter are then cross-multiplied creating a distribution of values for the hydrocarbons in place. The results are presented in the form of a histogram. For each of the parameters used in the HCIP calculation in the Monte Carlo program, due to heterogeneity and uncertainties a range of values usually minimum and maximum values are entered considering the best statistical distribution.

Statistics | Reservoir | Method

Number of Cases 2000 | Temperature 240 deg F | Bulk Volume x N/G Ratio

Histogramme Steps 100 | Pressure 5900 psig | Area x Net Thickness

Distribution type

	Distribution	Minimum	Maximum	Mode	Average	Standard Deviation	
Area	Triangular	450	950	475			acres
Thickness	Normal				230	23	feet
Porosity	Normal				0.19	0.03	fraction
Gas Saturation	Triangular	0.6	0.89	0.7			fraction
GOR	Normal				6800	200	scf/STB
Oil Gravity	Fixed Value	51					API
Gas Gravity	Fixed Value	0.88					sp. gravity

Figure 3.1: selected inputs for HCIP calculation

On entering the necessary parameters, the Calc button is clicked to enter the calculation screen. The condensate in place is calculated in terms of STOIIP .

SCGIIP	Expectation Gas	Rel. Freq. Gas	STOIIP	Expectation Oil	Rel. Freq. Oil
MMscf	fraction	fraction	MMSTB	fraction	fraction
37691	1	0	5.49548	1	0.0005
40831.9	1	0.0015	5.95343	0.9995	0.0005
43972.8	0.9985	0.002	6.41139	0.999	0.0025
47113.8	0.9965	0.001	6.86934	0.9965	0.0015
50254.7	0.9955	0.003	7.3273	0.995	0.002
53395.6	0.9925	0.0065	7.78526	0.993	0.005
56536.5	0.986	0.01	8.24321	0.988	0.01
59677.4	0.976	0.008	8.70117	0.978	0.011
62818.3	0.968	0.014	9.15913	0.967	0.0105
65959.3	0.954	0.0165	9.61708	0.9565	0.017
69100.2	0.9375	0.0195	10.075	0.9395	0.0175
72241.1	0.918	0.025	10.533	0.922	0.024
75382	0.893	0.033	10.991	0.898	0.0315
78522.9	0.86	0.032	11.4489	0.8665	0.033
81663.8	0.828	0.032	11.9069	0.8335	0.029

Figure 3.2: Calculated SCGIIP/STOIIP and their expectations/probabilities

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The Expectation Gas or Oil indicates the probability that the GIIP/CIIP is ≥ the stated value. Thus the gas and oil in place corresponding to expectations of 1 is the minimum gas and oil in place as per the data provided. Similarly, there is 50 % probability that the gas/oil in place is ≥ the gas/oil in place corresponding to expectation value of 0.5. The relative frequency oil is the proportion or percentage of data elements falling in that particular class of values. The summation of the relative frequency of the each fluid type will be equal to 1.

VIII. RESULTS

On initializing the Monte Carlo model and calculating, the results of the 10%, 50% and 90% probabilities are generated from the distribution.

Table 3: Results of HCIP and their level of confidence.

	Gas in place (MMscf)	Oil in place (MMSTB)
Mean Reward	115363	16.973
Standard Deviation	35756.5	5.35
90percent Probability	74502.2	10.95
50percent Probability	110302	16.21
10percent Probability	163328	23.96

The results from the Monte Carlo were generated in the form of a distribution which is shown below:

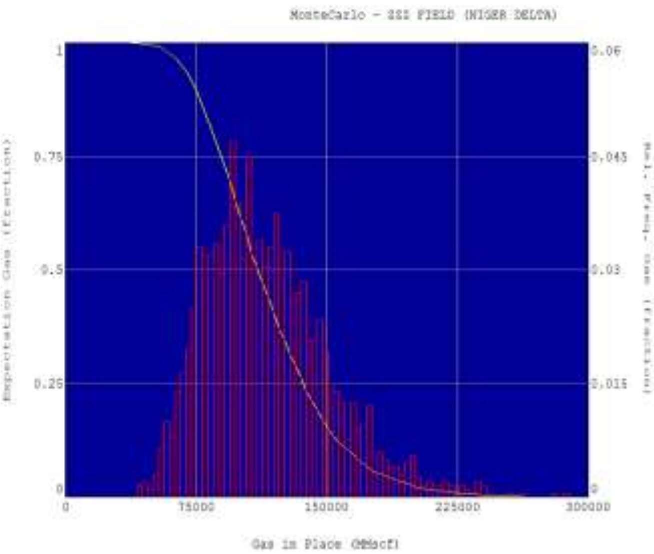

Figure 4.1: histogram showing probability distribution for the Gas in Place

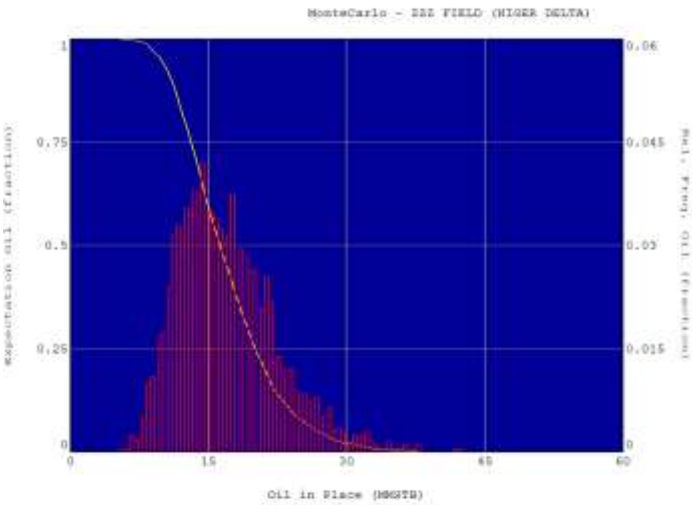

Figure 4.2: histogram showing probability distribution for the Condensate in Place

The Monte Carlo study gives rise to the following observations:
The Monte Carlo probabilistic P50 case which are; 110Bscf and 16mmstb were approximately 13Bscf and 3.7MMstb greater than volumetric estimate from an Independent 3rd party company.
The results indicates that the values of parameters that determine the P50 case where more optimistic than the P90 and P10 case due to the closeness of the figures of P50 case and those estimated by the other party.

IX. CONCLUSION

This study resulted to a more reasonable estimation of this gas condensate field using a probabilistic approach. The uncertainties and heterogeneities were accounted for using a range of possible values for the parameters used in HCIP estimation. PVT matching was done to ensure that the fluid was well characterized, and thus the gas and condensate volume were estimated. This probabilistic (Monte Carlo Simulation) method covered the range of possible outcomes with P90, P50 and P10 outcomes as low, best and high estimates respectively.

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X. RECOMMENDATION

To allow for a good volumetric based HCIP (GIIP&CIIP) estimate of immature fields with little or no sustained production history, probabilistic method of reserve estimation using Monte Carlo Technique can be used to estimate a reserve with uncertainties and heterogeneities. Also, proper fluid description and selecting the best statistical distribution for the HCIP computing parameters will improve the performance of the Monte Carlo Simulation and thus reasonable HCIP expectations and Probabilities can be generated.

Performance based HCIP estimate is reliable when there are reasonable reservoir rock and fluid data, production history and hence should continuously be used in validating the probabilistic volumetric HCIP estimate throughout the life of the field.

Development strategies of this gas condensate field will be tied on the reserve estimates considering also the economics and the best practice that will yield the optimum condensate recovery of this field.

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NOMENCLATURE

A- Area in acre
OHIP- Original Hyrodcarbon In Place
MBAL- Material Balance
P10- 10% Probability
P50- 50% Probability
P90%- 90% Probability
Bscf- Billion Standard Cubic Feet
MMstb- Million Stock Tank Barrel
CIIP- Condensate Initially In Place
G/ GIIP- Gas Initially In Place in scf
H- Thickness in ft
N/G- Net to Gross
Φ- Porosity
Sw- Water Saturation
Bgi- Initial Gas Formation Volume Factor
UR- Ulitmate Recovery
P/Z – Pressure/ Gas Deviation Factor
Gp- Cumulative Gas Production
We- Aquifer Influx
Wp- Cumulative Water Production
Bw- Water Formation Volume Factor
Caq- Aquifer Constant
TD- Total Depth
GOC- Gas Oil Contact
GDT- Gas Down TO
GWC- Gas Water Contact
GOR- Gas Oil Ratio
CGR- Condensate Gas Ratio
PVT- Pressure Volume Temperature
CCE- Constant Composition Expannsion
NC- Number of Cases
STOIIP- Stock Tank Oil Initially in Place
HDD- Horizontal Directional Drilling
EOR- Enhanced Oil In Place

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Challenges and Prospects of using HDD for laying Oil and Gas Pipelines in Nigeria, SPE 184315, presented at the 40th Society of Petroleum Engineers NAICE conference, Lagos, 2016.
Improving the Accuracy of Gas Measurements/Accounting in the Oil and Gas Industry – Pitfalls and Remedies (A Case Study of an Onshore Field in Nigeria), SPE 172398, presented at the 38th Society of Petroleum Engineers NAICE conference, Lagos, 2014.
Comparative economic analysis of using natural gas for liquefied natural gas production and converting natural gas to diesel through gas-to-liquid technology in Nigeria published in International Journal of Research in Engineering and Science (IJRES) 2014.

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