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Application of Sensitivity Analysis in Hydrocarbon Reserves Estimation

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***Abstract*— Reserve estimation in the petroleum industry is important for reservoir evaluation and investment. The economic viability of any exploration and production E & P project depends on the accuracy of its reserve which is carried out by using several input parameters such as porosity, net pay thickness, oil saturation, volume factor etc obtained from historical data. Due to uncertainties in reserve estimation, reserves need to be evaluated using stochastic method. Since most of the parameters are not uniform through the whole reservoir they are burdened with uncertainties, thus there is need to measure the impact of various parameters on oil initially in place (OIIP). In this study reserve estimation was done using MBAL software which employ the principle of material balance equation thereafter it was navigated to the tool tab whereby Monte Carlo simulation was selected and each parameter subjected to uncertainty quantification by varying distribution and measuring the sensitivity on the overall reserves. Uncertainty analysis conducted lead to the classification of reserve into low case (P90), base case (P50) and the high case (P10) which denote confidence level. Considering minimum and maximum values of different parameters with assumptions and various step sizes it was discovered that the impact of area of on OIIP was 71.8183MMSTB as mean reward (base case) and 76.7254MMSTB as high case, likewise the impact of net pay thickness produced 70.529MMSTB as base case and 71.8545MMSTB as high case. The impact of porosity gives 77.5659MMSTB and 79.8137MMSTB as P50 and P10 values. In the same scenario the impact of oil saturation on OIIP produces 75.80MMSTB as base case and 80.3083MMSTB as high case, impact of gas oil ratio GOR produces 72.0256MMSTB as mean reward and 77.44MMSTB as high case. Comparative analysis shows that porosity and oil saturation have the highest impact on OIIP and as such serious attention should be given to the two parameters with high impact on OIIP during reserves evaluation**

***Keywords*—Reserves, Monte-carlo Simulation, Hydrocarbon, Saturation, Porosity, OIIP and GOR**

I. INTRODUCTION

Reserve estimation is a very crucial part of reservoir management, exploitation, exploration and production. In reserve estimation, the goal is to principally evaluate a reservoir to be able to estimate, assess, the Stock Tank Oil Initially in Place (STOIIP) as well as analyze past and present performance of the reservoir (Dake, 2018).

To improve the clarity of these estimations, several reserve estimation techniques are employed and the techniques implemented by the petroleum engineer depend on the quality and maturity of the data available. There's just one reason for doing that: estimation of oil and gas reserves is inherently uncertain. More so, the extent and nature of the commercially recoverable hydrocarbons from the subsurface cannot be determined with a high degree of precision because recoveries from subsurface reservoirs depend largely on the heterogeneity of the reservoir rock and the type of reservoir drive mechanism. Reserve estimates are based on geologic and/or engineering data available at the time of estimate. Reserves estimation is one of the most essential tasks in the petroleum industry. It is the process by which the economically recoverable hydrocarbons in a field, area, or region are evaluated quantitatively (Cutler, 2014).

To better understand reserves estimation, a few important terms require definition. Original oil in place (OOIP) which refers to the total volume of hydrocarbon stored in a reservoir before production. Reserves or recoverable reserves are the volume of hydrocarbons that can be profitably extracted from a reservoir using existing technology. Resources are reserves plus all other hydrocarbons that may eventually become producible; this includes known oil and gas deposits present that cannot be technologically or economically recovered (OOIP and OGIP) as well as other undiscovered potential reserves (Adeolu *et al,* 2010).The reserve estimation methods discussed in this paper are primarily those methods typically applied to volumetric oil reservoirs. All of these methods (including our own) presume that the entire reservoir is being characterized by performance from a single well which is obviously not the case. However, in the case of moderate to low permeability reservoirs we can analyze data on a "per well" basis as each well drains its own particular volume and does not interfere with other wells in the system (Okpala, 2016).Resources are reserves plus all other hydrocarbons that may eventually become producible; this includes known oil and gas deposits present that cannot be technologically or economically recovered (OOIP and OGIP) as well as other undiscovered potential reserves (Adeolu *et al,* 2010).

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Using currently accepted methods for analysis, the estimation of original oil-in-place may require several iterations and/or secondary calculations, as well as other reservoir or well parameters. These methods can be time consuming, tedious, and are susceptible to errors for example, an incorrect value of any of the primary parameters will propagate the errors in the sequence of calculations. (Echendu *et al*, 2019).

1.1 Petroleum Reserves.

Reserves are estimated volumes of crude oil, condensate, natural gas, natural gas liquids, and associated substances anticipated to be commercially recoverable from known accumulations from a given date forward, under existing economic conditions, by established operating practices, and under current government regulations. Reserve estimates are based on geologic and/or engineering data available at the time of estimate. Reserves estimation is one of the most essential tasks in the petroleum industry. It is the process by which the economically recoverable hydrocarbons in a field, area, or region are evaluated quantitatively (Ali Azad, 2015).

1.1.1 Proved Reserves

Proved Reserves can be estimated with reasonable certainty to be recoverable under current economic conditions. Current economic conditions include prices and costs prevailing at the time of the estimate. Proved reserves must have facilities to process and transport those reserves to market that are operational at the time of the estimate, or there is a commitment or reasonable expectation to install such facilities in the future (Olubunmi *et al*, 2018).

In general, reserves are considered proved if commercial reducibility of the reservoir is supported by actual production or formation tests. The term proved refers to the estimated volume of reserve and not just to the productivity of the well or reservoir. In certain instances, proved reserves may be assigned on the basis of electrical and other type logs and/or core analysis that indicate subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing, or have demonstrated the ability to produce on a formation test(Lie & Mallison 2010).

The area of a reservoir considered proved includes:

i. The area delineated by drilling and defined by fluid contacts, if any, and
ii. The undrilled areas that can be reasonably judged as commercially productive based on available geological and engineering data.

In the absence of data on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive engineering or performance data

1.1.2 Unproved Reserves

Unproved Reserves are based on geological and/or engineering data like those used in the estimates of proved reserves, but when technical, contractual, economic or regulatory uncertainties preclude such reserves being classified as proved. They may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. (Hammonds & Hoffman, 2011). Unproved reserves are also based on geologic and/or engineering data like that used in estimates of proved reserves, but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. They may be estimated to be assuming future economic conditions different from those prevailing at the time of the estimate (Smith *et al,* 2011).Estimates of unproved reserves may be made for internal planning or special evaluations but are not routinely compiled. Unproved reserves are not to be added to prove reserves because of different levels of uncertainty. Unproved reserves may be divided into two sub classifications: probable and possible (Dake, 2015).

1.1.3 Probable Reserves

Probable reserves are less certain than proved reserves and can be estimated with a degree of certainty sufficient to indicate they are more likely to recover than not.

In general, probable reserves may include (Urayet 2004);

i. Reserves anticipated to be proved by normal step out drilling where subsurface control is inadequate to classify these reserves as proved, reserves in formations that appear to be productive based on log characteristics but that lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area,
ii. Incremental reserves attributable to infill drilling that otherwise could be classified as proved but closer statutory spacing had not been approved at the time of the estimate
iii. Reserves are attributable to an improved recovery method which has been established by repeated commercially successful applications when a project or pilot is planned but not in operation and rock, fluid, and reservoir characteristics appear favorable for commercial application.

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iv. Reserves in an area of a formation that has been proved productive in other areas of the field but subject area appears to be separated from the proved area by faulting and the geologic interpretation indicates subject area is structurally higher than the proved area.

v. Reserves attributable to a successful work-over, treatment, retreatment, change of equipment, or other mechanical procedure, where such procedure has not been proved successful in wells exhibiting similar behavior in analogous reservoirs, and

vi. Incremental reserves in a proved producing reservoir where an alternate interpretation of performance or volumetric data indicates significantly more reserves than can be classified as proved (Havlena, 2011).

1.1.4 Possible Reserves

Possible reserves are quantities of recoverable hydrocarbons estimated on the basis of engineering and geological data that are less complete and less conclusive than the data used in estimation of probable reserves. Possible reserves are less certain than probable reserves and can be estimated with a low degree of certainty, insufficient to indicate whether they are more likely to be recovered than not (Omoniyi 2011).

In general, possible reserves may include.

i. Reserves suggested by structural and/or stratigraphic extrapolation beyond areas classified as probable, based on geologic and/or geophysical interpretation,

ii. Reserves in formations that appear to be hydrocarbon bearing based on logs or cores but that may not be productive at commercial rates,

iii. Incremental reserves attributable to infill drilling that are subject to technical uncertainty, reserves attributable to an improved recovery method when a project or pilot is planned but not in operation and rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and

iv. Reserves in an area of a formation that has been proved productive in other areas of the field but subject area appears to be separated from the proved area by faulting and geologic interpretations indicates subject area is structurally lower that the proved area(*Zsolt & Julia 2009).*

1.2 Reserve Status Categories

Reserve status categories define the development and producing status of wells and/or reservoirs.

1.2.1 Developed

Developed reserves are expected to be recovered from existing wells (including reserves behind pipe). Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be subcategorized as producing or non-producing (Saltelli, 2010).

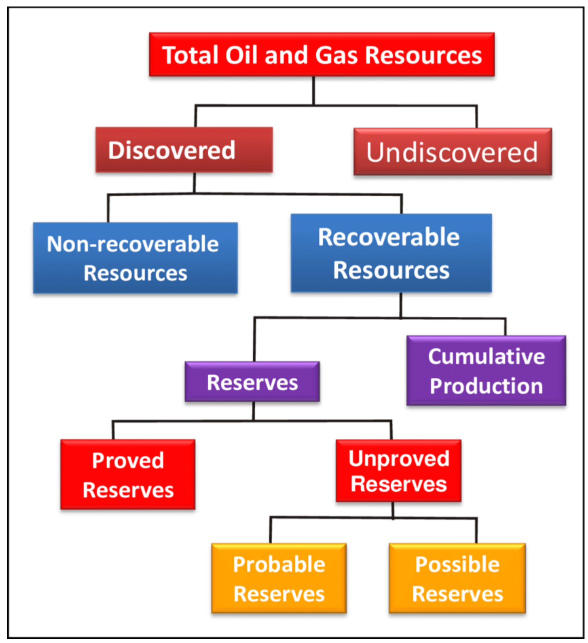

Figure 1.Types of Petroleum Reserves

II. MATERIALS AND METHOD

2.1 Data Acquisition And Simulation

The methodology employed for this research work for the estimation of volumetric oil initially in place (OOIP) as described by a suitable simulator used can be illustrated in the flow chart below:

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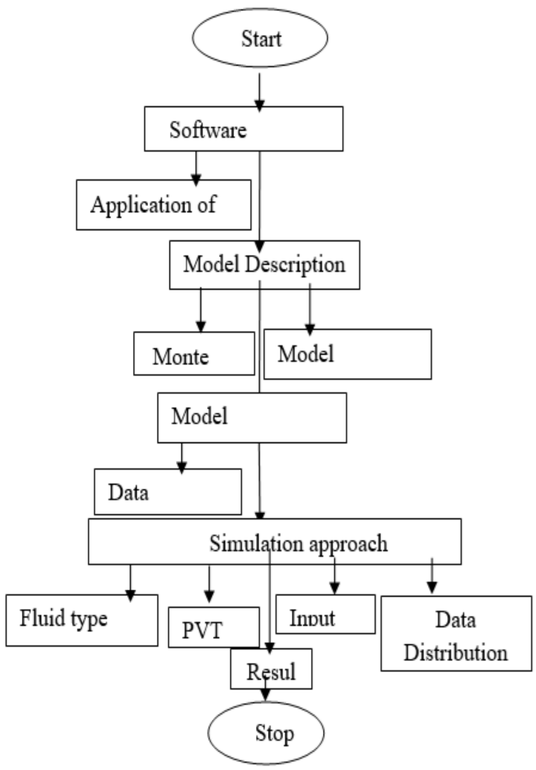

Figure 2. Simulation flowchart.

2.2 Data Acquisition.

The petro-physical data (Porosity, Net Pay Thickness, and Water Saturation) used for this research work were collected from wells logging of an unknown field but are reliable to model a common oil reservoir for the estimation of original oil in place, taking into consideration the level of uncertainty and variability on the data, in order to calculate the different types of oil reserves (1P, 2P and 3P). The data are basically categorized into dependent and independent data.

Estimates of fluid volume in a reservoir can be obtained from a variety calculation procedures and data sources. The estimated reserves can be gotten by inputting the various values of the independent parameter (variables) into the material balance equation whereby

$$N = \frac{7758Ah\phi(1 - S_{WC})}{B_{oi}} \quad 2.1$$

Where

N = Oil initially in place (STB)

ϕ = porosity (fraction)

A = reservoir area (areas)

h = net thickness of pay zone (feet)

S_{WC} = water saturation (frae).

B_{oi} = oil formation volume factor (RB /STB).

(A) Reservoir Porosity (ϕ)

The porosity of a rock is a measure of the storage capacity (pore volume) that is capable of holding fluids. Quantitatively, the porosity is the ratio of the pore volume to the total volume (bulk volume). This important rock property is determined mathematically, by the following generalized relationship.

$$\phi = \frac{V_p}{V_b} \quad (2.2)$$

As the sediments were deposited and the rocks were being formed during past geological time, some void spaces that developed became isolated from the other void spaces by excessive cementation. Mostly of the void spaces are interconnected while some of the pore spaces are completely isolated. This leads to two distinct types of porosity namely;

- Absolute porosity
- Effective porosity

(B) Saturation

Saturation is defined as that fraction or percent of the pore volume occupied by a particular fluid (oil, gas or water). This property is expressed mathematically by the following relationship

Applying the above mathematical concept of saturation to each reservoir fluid;

$$S_o = \frac{V_o}{V_p} \quad (2.3)$$

$$S_w = \frac{V_w}{V_p}$$

Thus, all saturation values are based on pore volume and not on the gross reservoir volume. The saturation of each individual place ranges between zero to 100 percent. By definition, the sum of the saturation is 100%, therefore

$S_g + S_o + S_w = 1$

The fluid in most reservoirs is believed to have reached a state of equilibrium and, therefore, will have become separated according to their density i.e. oil overlain by gas and underlain by water. In addition to the bottom (or edge) water, there will be connate water distributed throughout the oil and gas zones. The water in these zones will have been reduced to some irreducible minimum. The forces retaining the water in the oil and gas zones are referred to as capitally forces because they are important only in pore spaces of capitally size.

(C) Net Pay Thickness H

A fundamental prerequisite to reservoir performance prediction is satisfaction knowledge of the volume of oil originally in place. The reservoir is necessarily confused to certain geologic and fluid boundaries i.e. WOC so accuracy is imperatives. Within the confines of such boundaries, oil is contained in what is commonly referred to as Gross pay. Net pay thickness is that part of the reservoir thickness which contributes to oil recovery and is defined by imposing the flowing criteria.

i. Lower limit of porosity
ii. Lower limit of permeability
iii. Upper limit of water saturation

All available measurements performed on reservoir samples and in wells, such as core analysis and well logs, are extensively used in evaluating the reservoir net thickness.

(D) Oil Formation Volume Factor B_o

This is the ratio of the volume of oil (plus the gas in solution) at the prevailing reservoir temperature and pressure to the volume of oil at standard condition. It is denoted by Bo and is always greater than or equal to unity. The oil formation volume factor can be expressed mathematically as;

$$B_0 = \frac{(V_0)_{pt}}{(V_0)_{Sc}} \qquad (2.6)$$

A correlation of oil formation volume factor versus pressure shows that as the pressure is reduced below the initial reservoir pressure P_i, the oil volume increases due to oil expansion.

This behaviour results in an increase in the oil formation volume factor and will continue until the bubble-point pressure is reached. A P_b the oil reaches its maximum expansion and consequently attains a maximum value of Bob for the oil formation volume factors. As the pressure is reduced below P_b volume of oil and Bo are decreased as the solution gas is liberated. When the pressure is reduced to atmospheric pressure and the temperature to 60^0F, the volume of Bo is equal to one oil formation volume factor is a function of solution gas oil ratio, specific gas gravity $_g$, specific oil gravity $_o$ and temperature.

(E) Area Extent A

The calculation of area of the reservoir is done using PETREL software, can get the exact distance of the X and Y of the reservoir, multiplying these two values by each other we get the area of the reservoir, the margin is taken into consideration by allowing for a maximum and minimum value of the area with the calculated value in the middle of these two values.

2.3 Simulation Approach

The MBAL software was a useful tool used in this research work for the simulation of reserve estimation/evaluation and conducting sensitivity test on original oil in place with varying reservoir parameters. The program was launched and navigated to the tool tab. The tool tab provides options for different reserve estimation technique in which the Monte Carlo was selected to run the simulation. The Monte Carlo tool, depending on the number of cases chosen by the user, the program generate series of number of cases value for equal probability for each of the parameters used in the original hydrocarbon in place calculation. The number of cases values for each parameter is then cross multiplied creating a distribution of values for the hydrocarbon in place. The result is resented in the form of histogram.

Figure 3 shows the selected Monte Carlo tool for the simulation. The option tab interface provides information about the reservoir fluid model (oil in this case) Figure 4. The user defined entries are specified hypothetically since the data for the simulation are based on hypothesis.

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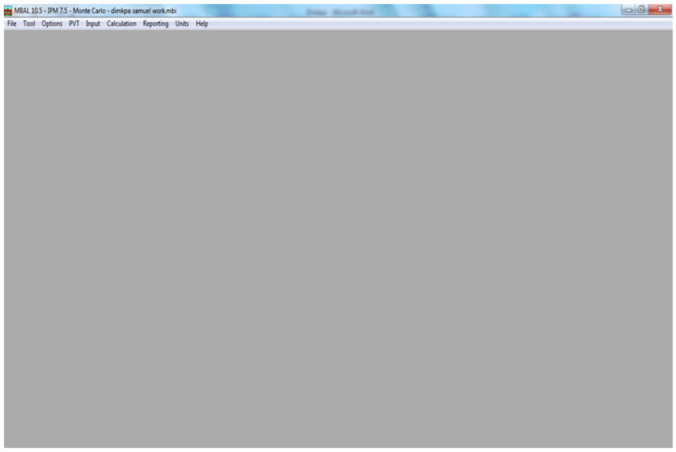


Figure 3. Monte Carlo tool interface

The PVT tab contains the important parameters which are called (fluid properties),from the fluid properties desirable data are entered for the reservoir modeling such as (formation (GOR), oil gravity, and etc.) are provided Figure 4. Since there is no available data for the simulation the PVT data were matched. Table 1 shows the PVT data which are to obtain matching.

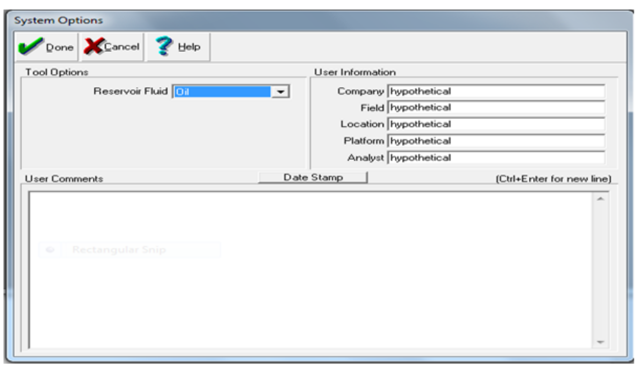


Figure 4. System option interface

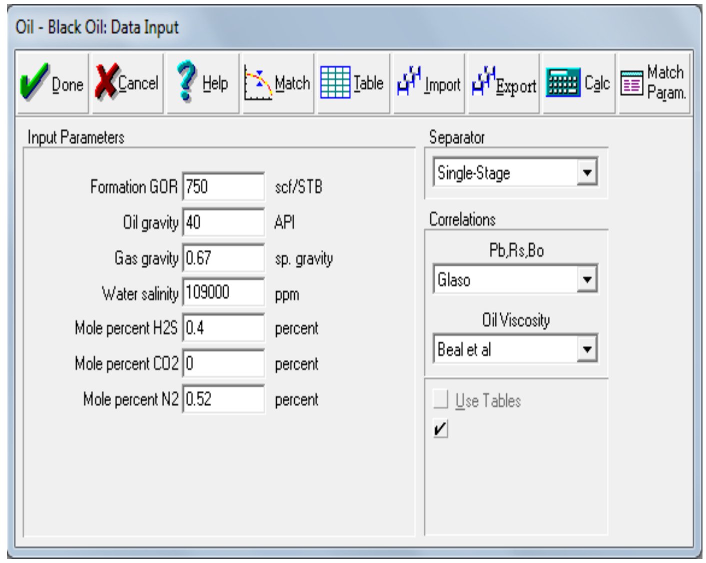
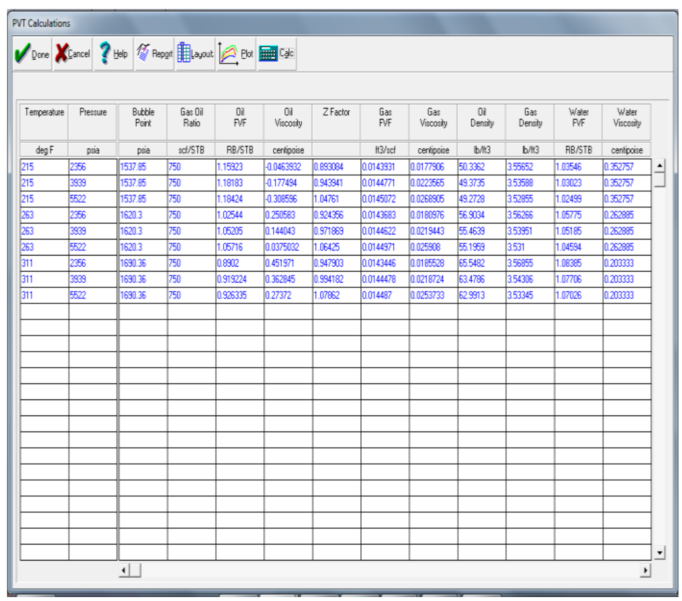


Figure 5. PVT Data

Since there is limited data, the PVT data calculated and the bubble point pressure (Pb), solution gas oil ratio (Rs) and oil formation value factor (Bo) were estimated using automatic calculation with a step of two.



Temperature	Pressure	Bubble Point	Gas Oil Ratio	Oil FVF	Oil Viscosity	Z Factor	Gas FVF	Gas Viscosity	Oil Density	Gas Density	Water FVF	Water Viscosity
deg F	psia	psia	scf/STB	RB/STB	centipoise		ft3/scf	centipoise	lb/ft3	lb/ft3	RB/STB	centipoise
215	2356	1537.85	750	1.15923	-0.0463932	0.893084	0.0143931	0.0177906	50.3362	3.55652	1.03546	0.352757
215	3939	1537.85	750	1.18183	-0.177494	0.943941	0.0144771	0.0223565	49.3735	3.53588	1.03023	0.352757
215	5522	1537.85	750	1.18424	-0.308596	1.04761	0.0145072	0.0268905	49.2728	3.52855	1.02499	0.352757
263	2356	1620.3	750	1.02544	0.250583	0.924356	0.0143683	0.0180976	56.9034	3.56266	1.05775	0.262885
263	3939	1620.3	750	1.05205	0.144043	0.971869	0.0144622	0.0219443	55.4639	3.53951	1.05185	0.262885
263	5522	1620.3	750	1.05716	0.0375032	1.06425	0.0144971	0.025908	55.1959	3.531	1.04594	0.262885
311	2356	1690.36	750	0.8902	0.451971	0.947903	0.0143446	0.0185528	65.5482	3.56855	1.08385	0.203333
311	3939	1690.36	750	0.919224	0.362845	0.994182	0.0144478	0.0218724	63.4786	3.54306	1.07706	0.203333
311	5522	1690.36	750	0.926335	0.27372	1.07862	0.014487	0.0253733	62.9913	3.53345	1.07026	0.203333

Figure 6. Automatic PVT Calculation results for other oil parameters

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2.3 Monte-Carlo Distribution And Sensitivity Input Parameters

This is basically where the whole estimation of original oil in place lies. Each of the parameters involved in the calculation of reserves; basically the PVT properties and the pore volume are represented by statistical distributions. Depending on the number of the cases (No chosen by the user, 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 then presented in a histogram. We link the probability of S_0 and porosity to reflect physical reality. If the porosity is near the bottom of the probability range, the S_0 will be weighed to be more likely to be near the top of the range. However, the uniform distribution is employed in this work to evaluate the uncertainties in our reserve volumetric calculation. To conduct sensitivity test on reservoir data as they affect the oil in place, the values of the data are estimated between its minimum and maximum values. Each parameter is ran at a time (with uniform distribution) while keeping the others fixed (fixed distribution). In this way, after, the calculation, the different volumetric reserve uncertainties (1P, 2P, 3P) of each parameter is examined. Table I represents the petro-physical distribution data.

TABLE I.
PARAMETER DISTRIBUTION

	Area (Ft)	Net thickness (ft)	Porosity (Frac)	Saturation (Frac)	Solution GOR	Oil gravity (API)	Gas gravity (Sp.gravity)
Min	3565	33	0.15	0.21	750	40	0.67
Max	4333	37	0.2	0.25	812	45	0.87
Mode	3705	35.5	0.245	0.233	820	43	71

At first, using uniform distribution method, a comparative effect of different uncertainties in pay net thickness estimated range of its minimum and maximum value was conducted on original oil in place. Every other parameter in the distribution was held fixed and the result thereof was examined, a total number of 500 cases and 20 histogram steps were run. This is the default number of cases chosen by the program. The other parameters for entry are the initial reservoir pressure and temperature of 5500 psia and 431°F.

The method of are multiplied by net pay thickness was chosen to calculate the original oil in place. The input for different parameters is from figures (3.9 to 3.15).

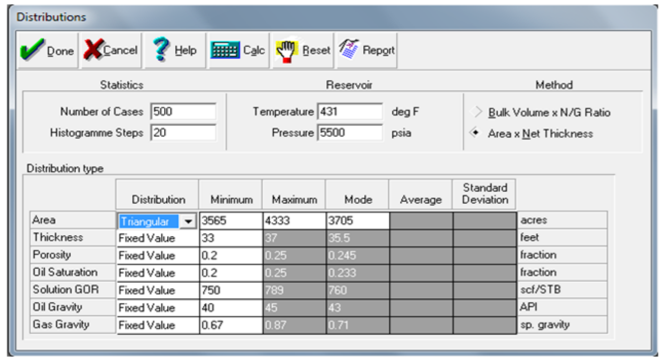

Figure 7 . Effect of area on OOIP

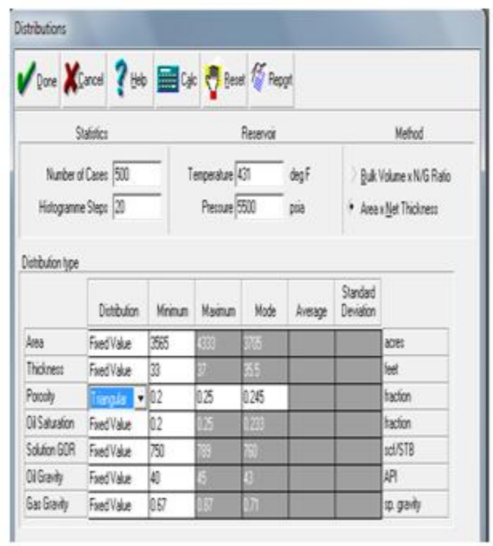

Figure 8. Effect of Porosity on OOIP

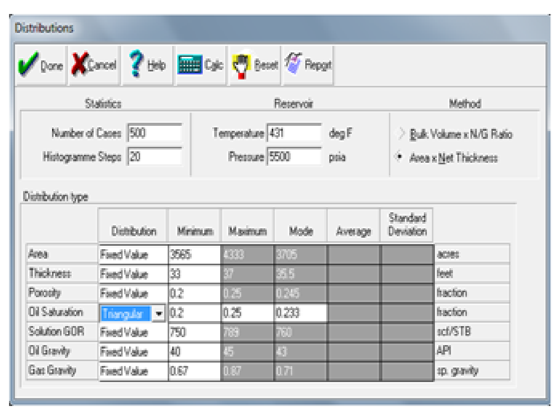

Figure 9. Effect of Oil Saturation on OOIP

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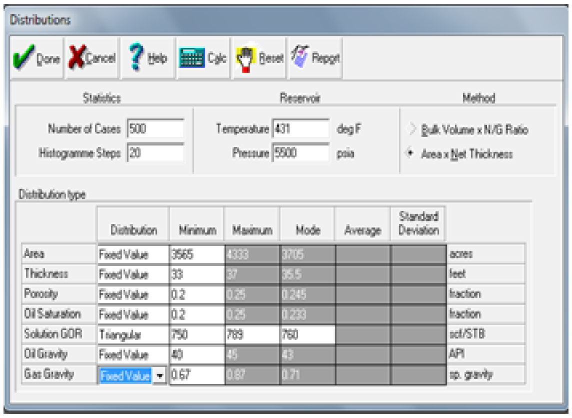

Figure 10. Effect of Solution GOR

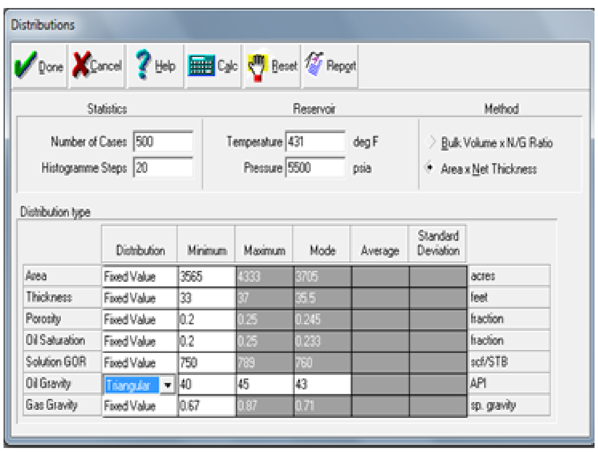

Figure 11. Effect of Oil Gravity OOIP

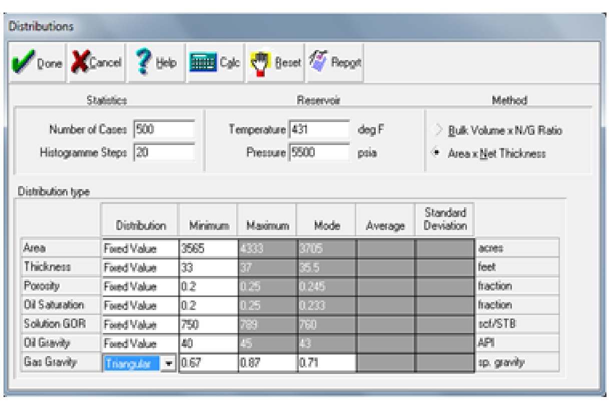

Figure 12. Effect of gas grav. On OOIP

III. Results And Discussion

3.1 Effect Of Area On OOIP.

From the result and plot obtained for varying the area extent of the reservoir, the presumed minimum and maximum oil in place was found to be 65.8716 and 78.2225 MMSTB respectively (figure 13). The probabilistic distribution of the oil in place with different area extent interval is shown in figure 14. From the plot, it shows that larger/highest percentage relative frequency oil corresponds to the mean reward OOIP of 71.9153 MMSTB. In same way, the corresponding value of expected oil to the relative frequency oil from the result summary was found to 0.708.

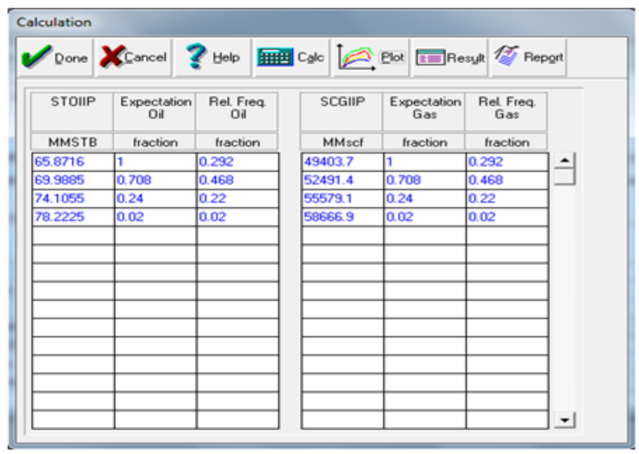

Figure 13. Res. Cal. for area

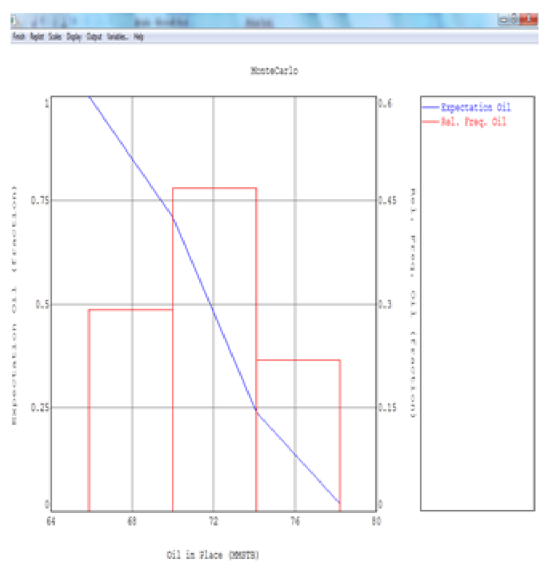

Figure 14. Histogram for area

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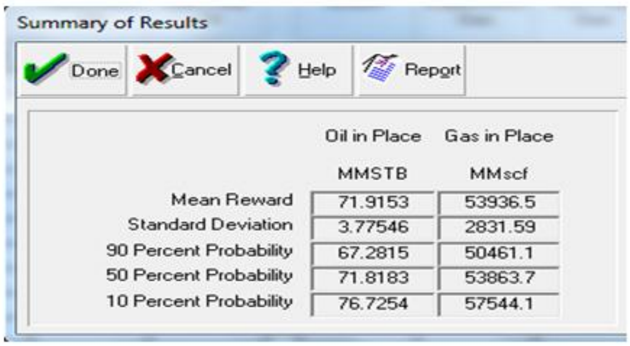
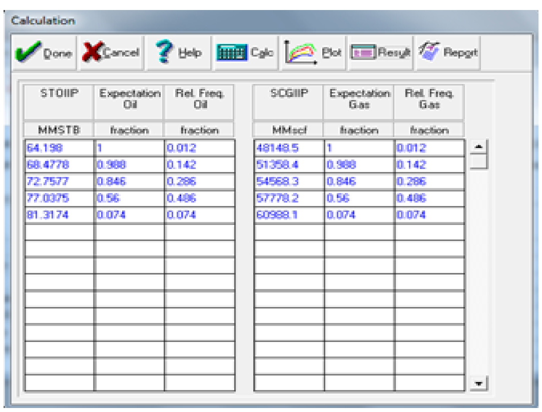


Summary of Results

	Oil in Place MMSTB	Gas in Place MMscf
Mean Reward	71.9153	53936.5
Standard Deviation	3.77546	2831.59
90 Percent Probability	67.2815	50461.1
50 Percent Probability	71.8183	53863.7
10 Percent Probability	76.7254	57544.1

Figure 15. Reserve classification based on area effect

As usual, all other parameter are held constant but porosity to determine its effect on reserve estimation. The minimum and maximum oil that was predicted as represented in figure 16 as (81.3174 and 64.199 MMSTB) . The relative frequency oil and expectation oil around the mean reward is 0.56 and 0.466.



Calculation

STOIIP MMSTB	Expectation Oil fraction	Rel. Freq. Oil fraction	SCGIIP MMscf	Expectation Gas fraction	Rel. Freq. Gas fraction
64.198	1	0.012	48148.5	1	0.012
68.4778	0.988	0.142	51358.4	0.988	0.142
72.7577	0.846	0.286	54568.3	0.846	0.286
77.0375	0.56	0.486	57778.2	0.56	0.486
81.3174	0.074	0.074	60988.1	0.074	0.074

Figure 16. Res. cal. for porosity

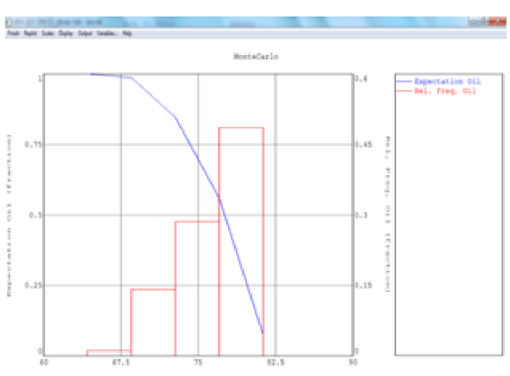
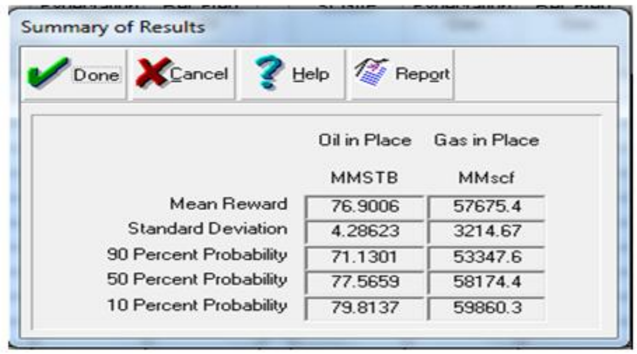


Figure 17. Histogram for porosity



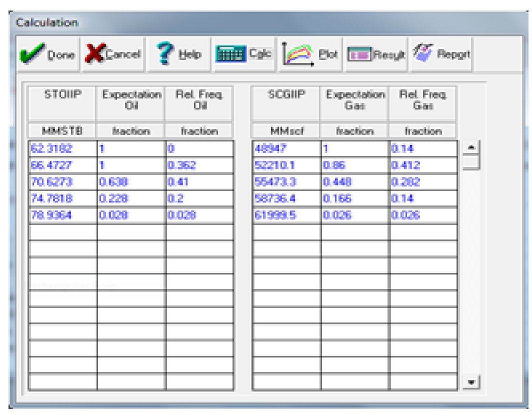
Summary of Results

	Oil in Place MMSTB	Gas in Place MMscf
Mean Reward	76.9006	57675.4
Standard Deviation	4.28623	3214.67
90 Percent Probability	71.1301	53347.6
50 Percent Probability	77.5659	58174.4
10 Percent Probability	79.8137	59860.3

Figure 18. Reserve classification based on porosity effect.

3.2 Effect Of GOR On OOIP

Minimum and maximum oil predicted to be 62.3182 and 78.9364 MMSTB corresponding to a relative frequency oil and expectation of 0.028 and 0.028 for maximum OOIP (figure 19). The histogram plot represented in figure 4.14. The mean reward is 72.2642 MMSTB with corresponding frequency oil of 0.41. This is also the highest percent distribution class of data.



Calculation

STOIIP MMSTB	Expectation Oil fraction	Rel. Freq. Oil fraction	SCGIIP MMscf	Expectation Gas fraction	Rel. Freq. Gas fraction
62.3182	1	0	48947	1	0.14
66.4727	1	0.362	52210.1	0.86	0.412
70.6273	0.638	0.41	55473.3	0.448	0.282
74.7818	0.228	0.2	58736.4	0.166	0.14
78.9364	0.028	0.028	61999.5	0.026	0.026

Figure 19. Reserve cal. for GOR

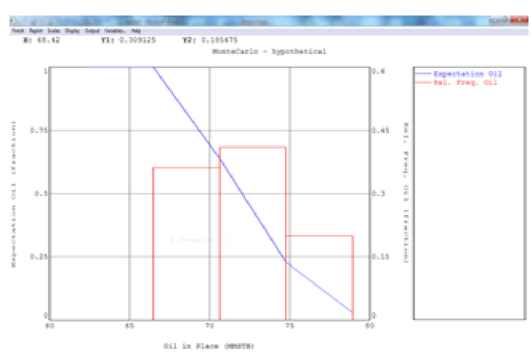


Figure 20. Histogram plot for GOR

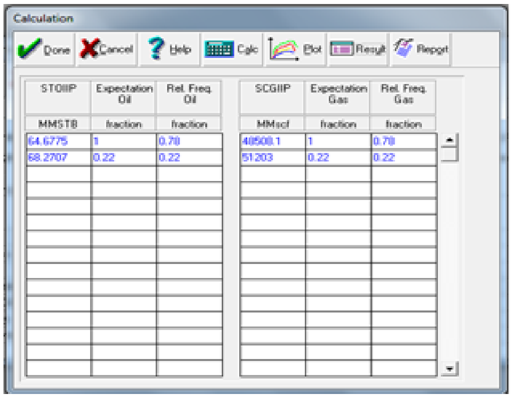


Figure 21. Reserve classification based on GOR effect.

3.3 Effect Of Oil Gravity On OOIP

The effect of oil gravity on original oil in place was predicted with a 0.00 MMSTB 10% probability volumetric estimation for both oil and gas. The minimum and maximum oil production is predicted to be 64.775 and 68.2707 MMSTB (Figure 22). Corresponding expectation oil and relative oil fraction is (1, 0.78) and (0. 022 and 0.22). The histogram plot to this is shown in Figure 23. The summary result shows that the mean reward original oil in place is 67.2646 MMSTB (figure 24).

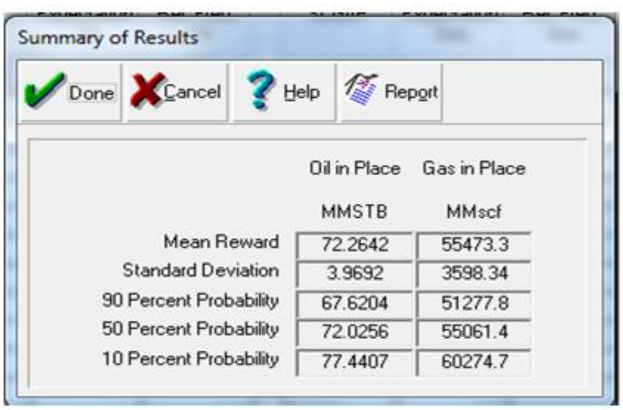


Figure 22. Res. Cal. for oil gravity

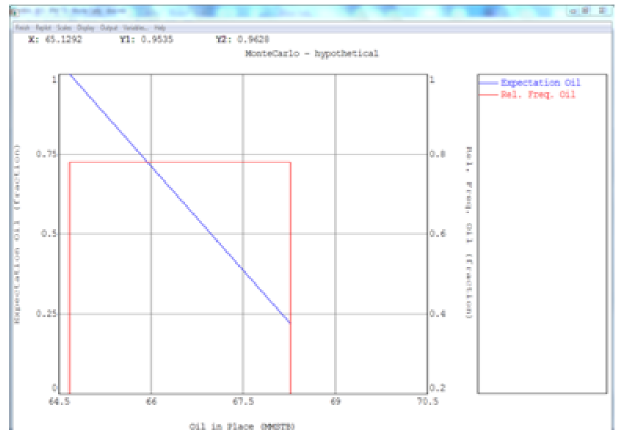


Figure 23. Histogram plot on oil gravity.

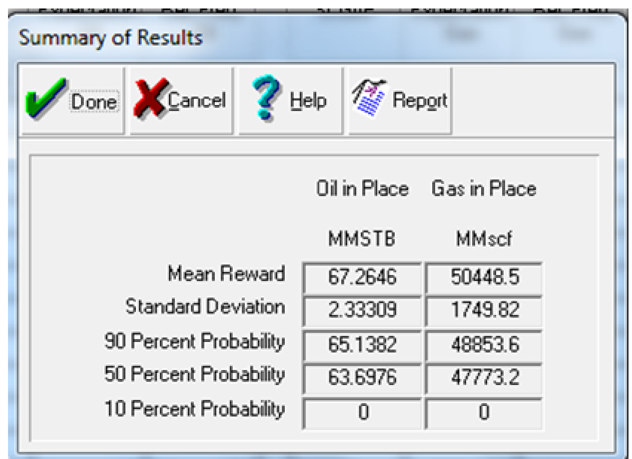


Figure 24: Reserve classification based on oil grav. Effect

The effect of the independent parameters as it affects original oil in place is illustrated in Table II

TABLE II.
RESERVE CLASSIFICATION DUE TO VARYING PARAMETER

	Area	Net thickness	porosity	Oil saturation	GOR	Oil gravity	Gas saturation
90%/ 1P	67.2851	67.631	71.1301	70.0575	67.6204	65.1382	73.61116
50%/ 2P	71.8183	70.529	77.5659	75.8021	72.0256	63.6976	84.0598
10%/ 3P	76.7254	71.855	79.8137	80.3083	77.4407	0	110.974

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IV. CONCLUSION

The scope of this research is to estimate the original oil in place using reserve estimated method (Monte Carlo tool). The following conclusions were drawn from this research:

i. The triangular and fixed parameters distribution was used for the estimation of the reserve, obtaining a mean reward volume which is the most accurate volume of hydrocarbon in the reservoir for each. The 50% probability distribution is the based- near accurate reserve classification.

ii. Gas gravity has the greatest effect on the original volumetric oil in place with a mean reward of 89.3949 MMSTB. The minimum and maximum oil in place are 63.937 and 134.973mmstb. The probability distribution of oil in place for 90%, 50% and 10% are 73.6116, 84.9598 and 110.974 MMSTB.

iii. Porosity is another parameter that also has a significant effect on the oil originally in place with a mean reward of 76.9009 MMSTB.

iv. Oil gravity has the least significant effect on the reserve concerned with a mean reward of 67.2646 MMSTB.

v. The field can be regarded as a marginal field due to the predicted reserve estimate.

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